Eastern Interconnection Planning Collaborative

# Eastern Interconnection Planning Collaborative

## Steady-State Modeling and Load-Flow Working Group

## Report for 2025 Summer and Winter Roll-Up Integration Cases

March 24, 2016

# Executive Summary

This report details the efforts of the Eastern Interconnection Planning Collaborative (EIPC) Steady-State Modeling and Load-Flow Working Group (SSMLFWG) to produce Eastern Interconnection roll-up integration cases for 2025 summer (2025S) and 2025 winter (2025W) and summarizes the assessments performed. The SSMLFWG includes representatives from each North American Electric Reliability Corporation (NERC)-registered Planning Authority (PA) party to the Eastern Interconnection Planning Cooperative Analysis Team Agreement.

The roll-up integration cases represent the base case for the Eastern Interconnection and a starting point for additional transfer analysis and analysis of scenarios developed with stakeholder input. The cases are integrated models of the expansion plans for the Eastern Interconnection as they existed in 2015, rather than a single "blueprint" for expanding the system. These cases provide solved power-flow modeling suitable as a starting point for interconnection-wide transmission analysis, and they are available to all stakeholders who have critical energy infrastructure information (CEII) clearance from the Federal Energy Regulatory Commission (FERC) to perform their own analyses.

As with all power-flow models, the 2025S and 2025W roll-up integration cases represent the power system for a particular "snapshot" in time (2025S and 2025W peak hours) based on actual facilities and planning forecasts as they existed to meet Reliability Standards at the time the model was developed. The SSMLFWG used transmission plans provided by each PA as the source of data for model development. These existing transmission plans are a product of each participating PA and the FERC-approved regional transmission planning processes for each of the participating EIPC members (as applicable) and extend through 2025. It should be noted that loads as well as generation and demand-side resources are inputs into the transmission expansion plans that each PA develops, which the respective load-serving entities (LSEs), market participants, or other applicable entities within each PA's jurisdiction provide. Because these inputs are continuously changing, the local and regional transmission plans will necessarily also continuously change, making them more up to date than what wide-area modeling can achieve. Nonetheless, wide-area modeling, such as the 2025S and 2025W roll-up integration cases, provides a sound basis for assessing interdependencies between and among regions. Potential constraints and efficiencies identified through interregional analysis are valuable inputs into local and regional processes where they can be assessed for inclusion into transmission expansion plans.

### Interregional Transmission (Gap) Analysis

The SSMLFWG performed two types of analyses. The first type was an interregional transmission "gap" analysis. The objective of this analysis was to identify potential interconnection-wide power-flow interactions that may result from the effects of plans of one Planning Authority on another. Once the PAs' plans were rolled up into a single model, first-contingency (N-1) analysis was performed. Potential constraints were identified for most planning authorities. Five PAs—Independent System Operator of New England (ISO-NE), the New York ISO (NYISO), the Midcontinent ISO (MISO), PJM Interconnection (PJM), and SERC Reliability Corporation (SERC)—identified potential solutions. Section 3.3 and Section 4.2 of the report show the identified potential constraints and solutions, respectively.

MISO reported six overloads in 2025S and no overloads in 2025W in the system-intact analysis. They reported 34 overloads in 2025S and 40 overloads in 2025W due to N-1 contingencies. PJM reported 14 overloads in 2025S and nine overloads in 2025W due to N-1 contingencies. PJM reported several lower voltage overloads in the reference cases for summer and winter. All are local loading issues due to some combination of local resource and load issues. Future reliability analyses will monitor these issues to determine the need for local upgrades. Additional available information is included in the comments of the detailed appendices.

The following points should be considered when assessing these results:

- Most voltage issues are inherently local in nature and amenable to local remedies and therefore are not a focus of interregional case preparation
- Many results are for lower-voltage facilities with greater local interest and more likely amenable to local system adjustments
- Many contingency results show little change from the reference case and are likely amenable to voltage tuning of the reference case voltage
- The large increase in the number of overloads shown by the winter results compared with the results for summer, and the fact that high voltages dominate the winter results, shows that local adjustments to the winter reference case is a likely solution for many of these issues
- Many high voltages can occur on transmission lines with voltages greater than 400 kilovolts (kV) often designed and operated at these higher voltages.

These results are from general screening and may not be issues at all. Overall, the PJM voltage results do not indicate significant interregional issues. Southwest Power Pool (SPP) reported four overloads in 2025S and no overloads in 2025W in the system-intact analysis. They reported 30 overloads in 2025S and nine in 2025W due to N-1 contingencies. The Northeast Power Coordinating Council (NPCC) reported nine overloads in 2025S and four overloads in 2025W in the system-intact analysis. They reported 72 overloads in 2025S and 54 overloads in 2025W due to N-1 contingencies. For the system-intact analysis, SERC reported seven overloads in 2025S and four overloads in 2025W. They reported 27 overloads in 2025S and 23 overloads in 2025W due to N-1 contingencies. The Florida Reliability Coordinating Council (FRCC) reported one overload in 2025S and no overloads in 2025W in the system-intact analysis. Under N-1 contingencies, FRCC reported 22 overloads in 2025S and 20 overloads in 2025W. Table ES-1 shows these results.

**Table ES-1**
**General Screening Results for 2025 Roll-Up Integration Cases**

| Planning Authority | Overloads with System Intact | | Overloads with N-1 Contingencies | |
|---|---|---|---|---|
| | 2025S | 2025W | 2025S | 2025W |
| **MISO** | 6 | 0 | 34 | 40 |
| **PJM** | Several lower voltage overloads | | 14 | 9 |
| **SPP** | 4 | 0 | 30 | 9 |
| **NPCC** | 9 | 4 | 72 | 54 |
| **SERC** | 7 | 4 | 27 | 23 |
| **FRCC** | 1 | 0 | 22 | 20 |

Solutions for these issues included upgrading facility capacities, adding circuits, following operating procedures, and re-dispatching generation.

## Linear Transfer Analysis

The second type of analysis was a linear transfer analysis for demonstrating the amount of power that can be reliably moved between regions. The intent of this analysis for the EIPC planning authorities was not to identify constraints for, and in turn identifying projects and increasing transfer capabilities, but rather to illustrate transfer capabilities of the transmission grid as currently planned (based on the 2025S and 2025W roll-up cases) under a number of transfer patterns. Table ES-2 and Table ES-3 show the regions and transfers between the regions for this analysis. (Refer to Section 1 for the full names of the participating planning authorities.)

**Table ES-2**
**Groupings of Planning Areas for Transfers**

| A | B | C | D | E | | F |
|---|---|---|---|---|---|---|
| FPL | MAPPCOR | New York ISO | PJM | Duke Energy Carolinas | SC | SPP |
| JEA | MISO | ISO New England | | Duke Energy Progress | Southern Company | |
| Duke Energy Florida | ATC | Ontario IESO | | LGE/KU | MEAG | |
| | ITC | NBSO | | GTC | Alcoa Power Generating, Inc. | |
| | Entergy | | | Power South | TVA | |
| | | | | SCEG | Electric Energy, Inc. | |

**Table ES-3**
**Transfers Performed**

| Source | Sink | | | | | |
|---|---|---|---|---|---|---|
| | A | B | C | D | E | F |
| A | | | | | Y | |
| B | | | Y | Y | Y | Y |
| C | | Y | | Y | | |
| D | | Y | Y | | Y | |
| E | Y | Y | | Y | | Y |
| F | | Y | | | Y | |

Each test case transferred 5,000 megawatts (MW) between the regions. Table ES-4 and Table ES-5 show the limits identified from this analysis and the regions involved in the limits. In some cases, the 5,000 MW transfer created no issues, indicating that the limit between the regions is greater than 5,000 MW.

**Table ES-4**
**Linear Transfer Results for Summer 2025 Case**

| Source | | Sink | | FCITC (MW) | Limited Planning Authority (Lim. PA) | Contingent Planning Authority (Con. PA) |
|---|---|---|---|---|---|---|
| A | FRCC | E | SERC | 343 | DEF-SEC | DEF |
| B | MISO | C | NPCC | 2,183 | PJM | NYISO |
| B | MISO | D | PJM | 4,419 | AMIL | N/A |
| B | MISO | E | SERC | >5,000 | N/A | N/A |
| B | MISO | F | SPP | 404 | EES-EAI | EES-EAI |
| C | NPCC | B | MISO | 1,969 | NYISO | NYISO |
| C | NPCC | D | PJM | 760 | NYISO | NYISO |
| D | PJM | B | MISO | >5,000 | N/A | N/A |
| D | PJM | C | NPCC | 1,630 | PJM | NYISO |
| D | PJM | E | SERC | >5,000 | N/A | N/A |
| E | SERC | A | FRCC | 2,356 | FPL | FPL |
| E | SERC | B | MISO | >5,000 | N/A | N/A |
| E | SERC | D | PJM | 4,337 | DVP | N/A |
| E | SERC | F | SPP | 336 | EES-EAI | EES-MISO / OKGE-SPP |
| F | SPP | B | MISO | 927 | OPPD | OPPD |
| F | SPP | E | SERC | 1,397 | OPPD | OPPD |

**Table ES-5**
**Linear Transfer Results for Winter 2025 Case**

| Source | | Sink | | FCITC (MW) | Lim. PA | Con. PA |
|---|---|---|---|---|---|---|
| A | FRCC | E | SERC | 1,130 | FPL | FPL |
| B | MISO | C | NPCC | 2,246 | PJM | NYISO |
| B | MISO | D | PJM | >5,000 | N/A | N/A |
| B | MISO | E | SERC | >5,000 | N/A | N/A |
| B | MISO | F | SPP | 1,275 | EES-EAI | EES-EAI |
| C | NPCC | B | MISO | 2,551 | PJM | NYISO |
| C | NPCC | D | PJM | 1,378 | NYISO | NYISO |
| D | PJM | B | MISO | 1,310 | PJM | N/A |
| D | PJM | C | NPCC | 2,109 | PJM | NYISO |
| D | PJM | E | SERC | 1,249 | PJM | N/A |
| E | SERC | A | FRCC | 2,592 | SOCO | SOCO |
| E | SERC | B | MISO | >5,000 | N/A | N/A |
| E | SERC | D | PJM | >5,000 | N/A | N/A |
| E | SERC | F | SPP | 1,046 | EES-EAI | EES-MISO / OKGE-SPP |
| F | SPP | B | MISO | 4,836 | OPPD | OPPD |
| F | SPP | E | SERC | 5,257 | OPPD | OPPD |

The transfer analysis results verify that the future transmission system as currently planned is capable of transferring more power than the long-term firm commitments modeled in the roll-up cases between the different regions, except for the transfers between NPCC and PJM. The negative transfer values significantly limiting a few of the transfers, as shown in the tables above, result from the preparation of the reference transfer case. This report and the appendices contain more details on all transfers. The additional transfer capability ranges from 336 MW to over 5,000 MW.

The planning processes for the EIPC members have many common aspects, but key differences in the processes exist between planning authorities throughout the very large Eastern Interconnection. These differences are expected outcomes given the diversity of regulations, topography, and characteristics of each Planning Authority’s electric transmission system. This report describes in detail the data submitted by each of the EIPC planning authorities, explains differences in the planning authorities’ respective planning processes, and assists stakeholders in understanding what the roll up contains.

Eastern Interconnection Planning Collaborative

# Contents

# Figure



# Tables

# Acronyms and Abbreviations

| | |
|---|---|
| 2025S | 2025 summer case |
| 2025W | 2025 winter case |
| AE | Atlantic Electric zone (PJM) |
| AEP | American Electric Power zone (PJM) |
| AMIL | Ameren-Illinois |
| APS | Allegheny Power zone (PJM) |
| ATSI | American Transmission Systems, Inc. (PJM) |
| BA | balancing area |
| BAA | balancing authority area |
| BGE | Baltimore Gas and Electric zone (PJM) |
| CARIS | Congestion Assessment and Resource Integration Study |
| CEII | critical energy infrastructure information |
| CELT Report | Forecast Report of Capacity, Energy, Loads, and Transmission |
| COMED | Commonwealth Edison zone (PJM) |
| Con. PA | Contingent Planning Authority |
| CPLE | the eastern BA of the Duke Energy Progress system |
| CPLW | the western BA of the Duke Energy Progress system |
| CRP | Comprehensive Reliability Plan |
| CSPP | Comprehensive System Planning Process |
| CT | combustion turbine |
| DAYTON | Dayton Power and Light zone (PJM) |
| DPL | Delmarva Power and Light zone (PJM) |
| DQE | Duquesne Lighting Company zone (PJM) |
| DEC | Duke Energy Carolinas |
| DEF | Duke Energy Florida |
| DEP | Duke Energy Progress |
| DNR | designated network resource |
| DOE | US Department of Energy |
| DSM | demand-side management |
| DUKE | Duke Energy (PJM) |
| DVP | Dominion Virginia Power |
| EE | energy efficiency |
| EES-EAI | Entergy–Arkansas, Inc. (MISO) |
| EES | Entergy |
| EIPC | Eastern Interconnection Planning Collaborative |
| EKPC | East Kentucky Power Cooperative (PJM) |
| EPP | Economic Planning Process |
| ERAG MMWG | Eastern Reliability Assessment Group, Multiregional Modeling Working Group |
| ES | Executive Summary |
| FCITC | first-contingency incremental transfer capability |
| FERC | Federal Energy Regulatory Commission |
| FPL | Florida Power and Light |
| FRCC | Florida Reliability Coordinating Council |
| FSA | Facility Study Agreement |

| | |
|---|---|
| GTC | Georgia Transmission Corporation |
| HVDC | high voltage direct current |
| IA | Interconnection Agreement |
| ICAP | installed capacity |
| IESO | Independent Electricity System Operator |
| ISO-NE | Independent System Operator of New England |
| ITC | International Transmission Company |
| ITO | Independent Transmission Organization |
| ITP | Integrated Transmission Plan |
| JCPL | Jersey Central Power and Light zone (PJM) |
| KU | Kentucky Utilities |
| kV | kilovolt |
| LG&E | Louisville Gas and Electric Company |
| Lim. PA | Limited Planning Authority |
| LM | load management |
| LSE | load-serving entity |
| LTE | long-term emergency |
| LTP | Local Transmission Owner Plan |
| LTPP | Local Transmission Planning Process |
| LTSG | Long-Term Study Group |
| MEAG | Municipal Electric Authority of Georgia |
| METED | Metropolitan Edison zone (PJM) |
| MISO | Midcontinent Independent System Operator |
| MPRP | Maine Power Reliability Project |
| MTEP | MISO Transmission Expansion Plan |
| MVA | megavolt-ampere |
| MVP | multivalue project |
| MW | megawatt |
| N-1 | first contingency |
| N-1-1 | second contingency; two lines out during a maintenance case study |
| N-2 | second contingency; two lines out in a peak case study |
| NBSO | New Brunswick System Operator |
| NERC | North American Electric Reliability Corporation |
| NEEWS | New England East–West Solution |
| NEPA | National Environmental Policy Act |
| NITS | network-integrated transmission service |
| NPCC | Northeast Power Coordinating Council |
| NTC | Notification to Construct |
| NYCA | New York Control Area |
| NYISO | New York Independent System Operator |
| NYPSC | New York State Public Service Commission |
| OKGE | Oklahoma Gas and Electric |
| OPA | Ontario Power Authority |
| OPPD | Omaha Public Power District |
| PA | Planning Authority |
| PAR | phase-angle regulator |
| PEC | Progress Energy Carolina |

| | |
|---|---|
| PECO | PECO Energy zone (PJM) |
| PENLC | Pennsylvania Electric zone (PJM) |
| PEPCO | Potomac Electric Power zone (PJM) |
| PGDP | Paducah Gaseous Diffusion Plant |
| PJM | PJM Interconnection, LLC |
| PL | PPL Electric Utilities (subzone of PLGroup) (PJM) |
| PPTPP | Public Policy Transmission Planning Process |
| PS | Public Service Electric and Gas zone (PJM) |
| PSP | power system planning |
| PTP | point-to-point |
| PV | photovoltaic |
| RECO | Rockland Electric (East) zone (PJM) |
| RNA | Reliability Needs Assessment |
| ROW | right-of-way |
| RPP | Reliability Planning Process |
| RTEP | Regional Transmission Expansion Plan |
| RTO | Regional Transmission Operator |
| SCE&G | South Carolina Electric and Gas |
| SCED | security-Constrained economic dispatch |
| SCPSA | Santee Cooper |
| SEC | Seminole Electric Cooperative, Inc. |
| SEMA | southeastern Massachusetts |
| SERC | SERC Reliability Corporation |
| SIA | System Impact Assessment |
| SMEPA | South Mississippi Electric Power Association |
| SPP | Southwest Power Pool |
| SPS | special protection system |
| SSMLFWG | Steady-State Modeling and Load-Flow Working Group |
| TDF | Transfer Distribution Factor |
| TOTS | transmission owners' transmission solution |
| TVA | Tennessee Valley Authority |
| TYSP | Ten-Year Site Plan |
| UGI | UGI Utilities (subzone of PLGroup) (PJM) |
| VEPCO | Virginia Electric and Power Company (PJM) |

# Section 1
# Introduction

On May 21, 2009, representatives from planning authorities (PAs) in the Eastern Interconnection formed the Eastern Interconnection Planning Collaborative (EIPC). This group agreed to initiate technical work for facilitating the coordination of existing transmission plans and conducting reliability analyses of the combined interconnection system and other studies to support state, provincial, regional, and federal public policy decision making.

The following planning authorities are either members of the EIPC or are providing data and input to the roll-up and integration process:

1. Alcoa Power Generating, Inc.
2. Duke Energy Carolinas (DEC)
3. Duke Energy Florida (DEF)
4. Duke Energy Progress (DEP)
5. Electric Energy Inc.
6. Entergy Services, Inc. on behalf of the Entergy Corporation Utility Operating Companies (Entergy)
7. Louisville Gas and Electric Company (LG&E) and Kentucky Utilities (KU) Company (Louisville/Kentucky Utilities)
8. Florida Power & Light (FPL)
9. Georgia Transmission Corporation (GTC)
10. Independent Electricity System Operator (IESO) (Ontario, Canada)
11. International Transmission Company (ITC)
12. ISO New England, Inc. (ISO-NE)
13. JEA (Jacksonville, Florida)
14. Midcontinent Area Power Pool, by and through its agent, MAPPCOR
15. Midcontinent Independent Transmission System Operator, Inc. (MISO)
16. Municipal Electric Authority of Georgia (MEAG)
17. New York Independent System Operator, Inc. (NYISO)
18. PJM Interconnection, LLC (PJM)
19. PowerSouth Energy Coop
20. Santee Cooper (SCPSA)
21. South Carolina Electric and Gas (SCE&G)

22. Southern Company Services Inc. (Southern), as agent for:
    a. Alabama Power Company
    b. Georgia Power Company
    c. Gulf Power Company
    d. Mississippi Power Company
23. Southwest Power Pool (SPP)
24. Tennessee Valley Authority (TVA)

The EIPC complements the regional transmission expansion plans developed each year and supports the Federal Energy Regulatory Commission (FERC) Order 890 regional planning processes. It uses these Order 890 and Order 1000 regional planning processes and selected interconnection-wide webinars and meetings to solicit input and feedback from stakeholders. In addition to work conducted under a US Department of Energy (DOE) grant, the EIPC self-funds the efforts to develop interconnection-wide models, test these models with increased transfers, identify potential gaps that could have an impact on reliability, and analyze scenarios developed with stakeholder input. For the 2015 to 2016 cycle, EIPC modeled two load cycles of a one-year period—2025 summer (2025S) and 2025 winter (2025W). The EIPC continues to provide a transparent and collaborative Eastern Interconnection-wide venue to all interested stakeholders through regional Order 890 and Order 1000 processes and interconnection-wide webinars and meetings.

The purpose of the Steady-State Modeling and Load-Flow Working Group (SSMLFWG) of the EIPC is as follows:

1. Modify/create steady-state load-flow models
2. Conduct steady-state load-flow analysis (including transfer capability)
3. Analyze selected scenarios based on selected North American Electric Reliability Cooperation (NERC) Reliability Standards
4 Report results to stakeholders (subject to applicable Critical Energy Infrastructure Information [CEII] requirements)

Figure 1-1 depicts an overview of the process employed by the EIPC SSMLFWG.[1]

[1] The EIPC website contains information about the work to be performed: http://www.eipconline.com/Non-DOE_Documents.html and http://www.eipconline.com/Stakeholder_Activities.html.

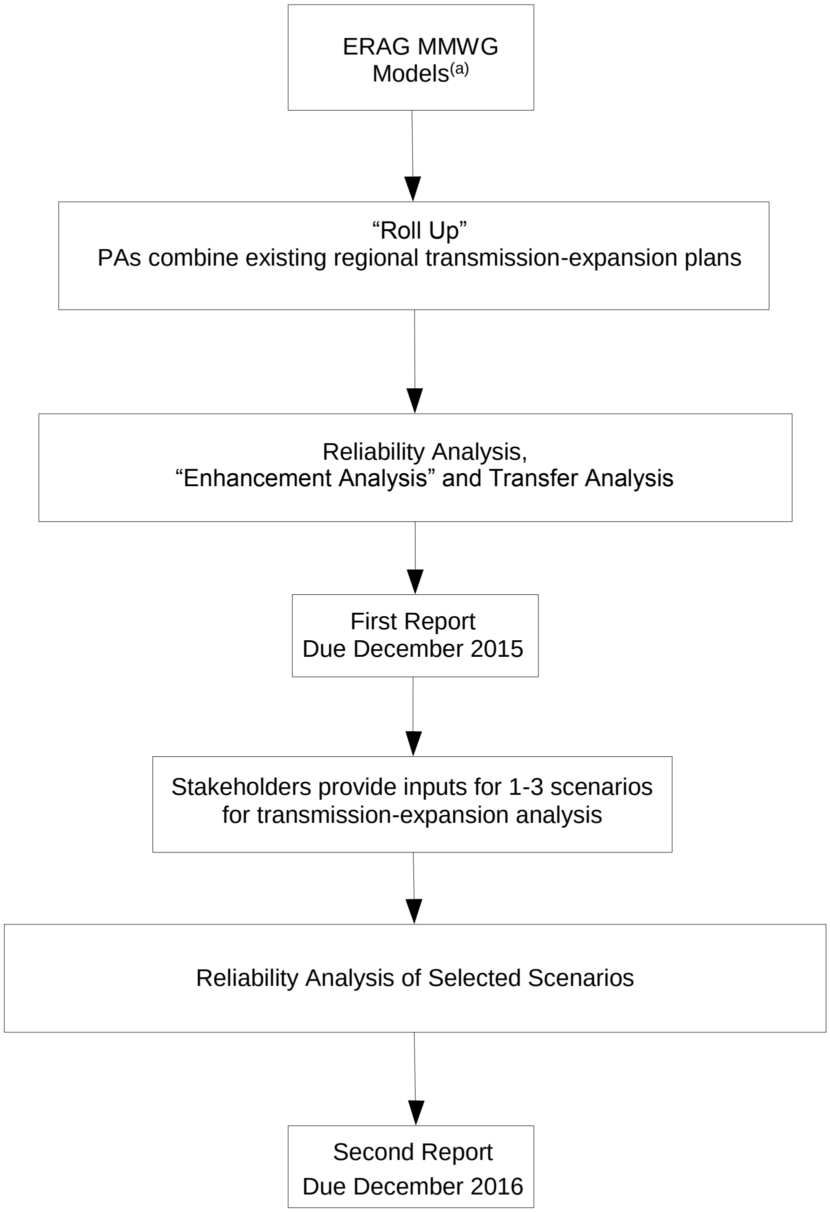


**Figure 1-1: EIPC Planning Analysis Process.**

(a) "ERAG MMWG" stands for Eastern Reliability Assessment Group, Multiregional Modeling Working Group.

# Section 2
# Planning Authorities' Assumptions

This section details the assumptions made by each PA in developing the 2025 summer and winter roll-up integration cases. These include assumptions for load forecasting, the treatment of demand resources and energy efficiency (EE), interchanges with other systems, future transmission and generation project inclusion, and generation dispatch.

In some cases, one or more PA systems may be incorporated into the model roll-up of another PA, without duplication. Georgia Transmission Corporation and MEAG have noted where their information for certain sections are included in Southern Company's responses.

The starting point in creating the 2025 roll-up integration cases included the EIPC Eastern Reliability Assessment Group, Multiregional Modeling Working Group (ERAG MMWG) 2014 series cases for the 2020 winter peak and 2025 summer peak. Each PA updated its portion of this model or submitted a new model of its respective system, all of which were then assembled into one complete power-flow model. To assure the accuracy of the database, the SSMLFWG reviewed the case several times before validating it or performing any study work.

## 2.1 Load Forecasts and Growth Rates

This section describes the load growth rates represented in the roll-up integration case for each EIPC Planning Authority through 2025. In addition to the growth rates, the amount of load and origination of the data are discussed. The annual average growth rates are the rates used by each PA in its regional transmission planning processes.

The load forecasts provided by each PA were based on load projections, typically based on the 50/50 load projection where there is a 50% chance the actual load will be higher or lower than the forecast. The load forecasts were not adjusted to provide a coincident peak for the entire Eastern Interconnection. It is appropriate to apply non-coincident peak load forecasts when planning for transmission needs over large regional areas, and is in fact the obligation of each NERC-registered PA to plan for the critical system conditions for the area it is responsible for. This approach ensures that the transmission system performance of each PA is reliable, as required by NERC Reliability Standards.

Because the roll-up integration case is based on current transmission plans as of 2014, the vintage of the aggregated load-serving entity (LSE) forecasts is generally late 2014 or early 2015.

### Alcoa Power Generating, Inc.

APGI Yadkin Division's load growth from 2010 to 2020 is less than 1.0%. Alcoa serves its own load. The load forecast is based on a history of usage. No loads other than Yadkin's are in their area, therefore by definition this load is a coincident peak.

APGI Tapoco Division's load includes South Plant. APGI Tapoco has no generators; it purchases power to serve its load.

### Duke Energy Carolinas

The Duke Energy Carolinas (DEC) load forecasting group developed the load forecast in 2014 using data including the forecasts of individual LSEs in the DEC footprint. Duke Energy Carolinas expects an average growth rate of 1.4% through 2025S for a control area load of approximately 24,000 MW in 2025S and 22,770 MW in 2025W, incorporating the demand from DEC's wholesale customers coincident with DEC's peak.

### Duke Energy Florida

The Duke Energy Florida (DEF) load forecasting group developed the load forecast in 2014 using data including the forecasts of individual LSEs in the DEF footprint. Duke Energy Florida expects an average growth rate of 1.14% through 2025W for a control area non-coincident peak load of approximately 13,991 MW in 2025S and 14,581 MW in 2025W.

### Duke Energy Progress

Duke Energy Progress (DEP) updates its power-flow models on an annual basis. Loads plus losses at the transmission level are scaled to match the system forecast coincident peak load for each load level. Duke Energy Progress expects an average growth rate of 1.64% of its area through 2025S for a balancing area (BA) load of approximately 15,426 MW in 2025S and 14,956 MW in 2025W.

### Electric Energy Inc.

Electric Energy Inc. has no native load and therefore does not compile a load forecast.

### Florida Power and Light

The load modeled in the Florida Power and Light (FPL) area in the 2025 roll-up integration case reflects an average annual growth rate of 1.72% for the 2015 to 2025 period. The load assumptions are based on the official FPL 2013 coincident load forecast as filed with the Florida Public Service Commission in the *Ten-Year Site Plan* (TYSP) document.[2]

### Georgia Transmission Corporation

Georgia Transmission Corporation (GTC) prepares a load forecast annually through input from its member cooperatives. The load forecast included in the roll-up case was prepared in 2015, and the average annual growth rate is approximately 2.5% for 2016 to 2025. GTC's forecasted load is included in the Southern Balancing Authority as coincident with other Georgia load.

### Independent Electricity System Operator

The Independent Electricity System Operator (IESO) produces a load forecast regularly. As of March 2015, the Ontario non-coincident normal weather peak demand for 2025S and 2025W was forecasted to be 24,580 MW and 22,455 MW, respectively, reflecting a net annualized 10-year growth rate of 0.35%. The normal weather scenario is based on historical weather from the past 31 years and represents typical weather on a monthly basis. The main reasons for the small growth

[2] Florida Power and Light, *Ten-Year Power Plant Site Plan: 2015–2014* (April 2015), https://www.fpl.com/company/pdf/10-year-site-plan.pdf.

rate of the Ontario demand are lower economic growth, energy conservation, the use of embedded generation, and changes in electricity consumption patterns due to the introduction of time-of-use rates at the residential level.

### ISO New England

ISO New England (ISO-NE) expects an average annual growth rate of 1.50% through 2025S for a control area demand of approximately 32,891 MW (accounting for load and losses) based on load forecasts in the ISO-NE *2014 to 2023 Forecast Report of Capacity, Energy, Loads, and Transmission* (CELT).[3] With the addition of 3,918 MW of demand-resource load reduction, ISO-NE estimates the control area demand (load and losses) to be 28,973 MW. In 2025W, the ISO-NE control area demand (load and losses) is expected to be 24,810 MW. With the addition of 3,795 MW of demand-resource load reduction, ISO-NE estimates the control area demand (load and losses) to be 21,015 MW.

### JEA

The total internal demand (firm and non-firm demands) for the summer peak for JEA is forecasted to increase at an average annual growth rate of 0.95% to 2,851 MW for summer 2024, as used in the roll-up integration case. The forecast was done in April 2015 and incorporates the non-coincident peak demand from JEA's wholesale customer located adjacent to JEA's service territory in Northeast Florida.

### Louisville Gas and Electric Company and Kentucky Utilities

All load-serving entities on the Louisville Gas and Electric Company and Kentucky Utilities (LG&E and KU) transmission system provide load forecasts annually of the network load levels. The balancing authority forecasted coincident load in the 2025S EIPC roll-up case is 7,745 MW and 6,606 MW in the 2025W EIPC roll-up case.

The LG&E and KU's native LSE load level is based on a 50/50 forecast with all curtailable loads being served. The native load forecast was developed in fall 2014 on the basis of 2014 summer and 2013 winter actual loads. The LG&E and KU native LSE expects an average growth rate of approximately 1.0% from 2015 through 2025.

### Municipal Electric Authority of Georgia Power

A load forecast is prepared annually through input from Municipal Electric Authority of Georgia (MEAG) participants. The load forecast included in the roll-up case was prepared in 2014, and the average annual growth rate is 1.0% for 2015 to 2025. MEAG's load forecast is included in the Southern Balancing Authority as coincident with other Georgia load.

### Midcontinent ISO

For Midcontinent ISO (MISO) members, model load is reflective of LSE forecasts as provided by the transmission owners through the *MISO Transmission Expansion Plan* (MTEP) reliability model

---

[3] ISO New England, *2014–2023 Forecast Report of Capacity, Energy, Loads, and Transmission* (May 1, 2014), http://www.iso-ne.com/static-assets/documents/trans/celt/report/2014/2014_celt_report_rev.pdf.

building process.[4] For transmission planning purposes, the non-coincident peak loads of the member systems are used in the MTEP models. This approach ensures that the performance of the transmission system is reliable at the member system level, as required by the NERC planning standards.

In 2014, MISO member systems provided power-flow model peak-load projections for the MTEP 2015 vintage model that was the basis of the EIPC roll-up for the MISO system.

The demand projections included in the roll-up integration case for the MISO portion of the EIPC roll-up case are consistent with the MISO section in NERC's *2015 Long-Term Resource Assessment* report.

### New York ISO

The New York ISO (NYISO) is forecasting a base 2025 coincident summer and winter peak load for the New York Control Area (NYCA) of approximately 35,219 MW and 25,020 MW, respectively, which is inclusive of statewide energy-efficiency programs and represents an average annual growth rate for the summer of 0.52% through 2025, as documented in the NYISO *2015 Load & Capacity Data* report.[5]

### PJM Interconnection

PJM annually prepares a detailed, independent load forecast for PJM overall and each of its zones and sub-regions. The January 2015 forecast is the basis for the PJM system contained in the EIPC roll-up system.[6] Summer peak load growth for the PJM Regional Transmission Operator (RTO) (including American Transmission System integrated into PJM during 2011 and the East Kentucky Power Cooperative integrated into the PJM RTO on June 1, 2013) is projected to average 1.1% per year over the next five years and 1.0% over the next 10 years (down from 1.3% in the 2013 EIPC report). The PJM RTO summer coincident peak is forecasted to be 164,443 MW in 2020, a five-year increase of 14,148 MW, and reach 171,579 MW in 2025, a 10-year increase of 21,284 MW. Annualized 10-year growth rates for individual PJM zones range from 0.4% to 1.7% (compared with 0.7% to 2.0% in the 2013 EIPC report). The roll-up case is based on the PJM coincident peak forecast. Table 2-1 presents the PJM area-by-area coincident peak forecasts. The annual PJM forecasts prepared by PJM, however, also include non-coincident peak forecasts used in the series of annual planning analyses. In addition, the annual series of planning analyses examine ranges of load levels. The PJM forecast is based on historical data from January 1998 through August 2014. The models were simulated with weather data from 1973 through 2013, generating 533 scenarios. The economic forecast used was Moody's analytics' October 2014 release. Because PJM performs complete integrated modeling for both non-coincident area forecasts and the coincident RTO forecast, it does not need a process to "roll up" area forecasts for determining the RTO forecast.

---

[4] MTEP plans are available at https://www.misoenergy.org/Planning/TransmissionExpansionPlanning/Pages/TransmissionExpansionPlanning.aspx.

[5] New York ISO, *2015 Load and Capacity Data* (April 2015), http://www.nyiso.com/public/webdocs/markets_operations/services/planning/Documents_and_Resources/Planning_Data_and_Reference_Docs/Data_and_Reference_Docs/2015%20Load%20and%20Capacity%20Data%20Report.pdf.

[6] The complete underlying assumptions and process for the development of this forecast are available at http://www.pjm.com/planning/resource-adequacy-planning/load-forecast-dev-process.aspx.

**Table 2-1**
**2015 PJM Area-by-Area Coincident Peak-Load Forecasts for 2020 and 2025 and 5- and 10-Year Average Annual Growth Rates (MW, %)**

| PJM Area | 2013 Coincident Peak Load (MW) | 2014 Coincident Peak Load (MW) | 2015 Coincident Peak Load (MW) | 2020 Forecast Coincident Peak Load (MW) | 2025 Forecast Coincident Peak Load (MW) | 5-year Average Annual Growth Rate | 10-year Average Annual Growth Rate |
|---|---|---|---|---|---|---|---|
| **AE** | 2,450 | 2,500 | 2,450 | 2,658 | 2,727 | 0.8% | 0.7% |
| **AEP** | 22,230 | 22,070 | 22,290 | 23,563 | 24,363 | 0.9% | 0.8% |
| **APS** | 8,110 | 8,200 | 8,350 | 8,902 | 9,336 | 1.2% | 1.1% |
| **ATSI** | 12,490 | 12,670 | 12,640 | 13,072 | 13,321 | 0.5% | 0.4% |
| **BGE** | 6,540 | 6,540 | 6,490 | 7,200 | 7,491 | 1.0% | 0.9% |
| **COMED** | 20,770 | 20,870 | 20,900 | 23,572 | 24,918 | 1.4% | 1.3% |
| **DAYTON** | 3,120 | 3,110 | 3,170 | 3,586 | 3,797 | 1.4% | 1.3% |
| **DPL** | 3,680 | 3,750 | 3,750 | 4,237 | 4,402 | 1.0% | 0.9% |
| **DQE** | 2,780 | 2,720 | 2,780 | 2,956 | 3,029 | 0.8% | 0.6% |
| **DUKE** | 4,970 | 5,070 | 5,080 | 5,536 | 5,766 | 0.9% | 0.9% |
| **EKPC** | 1,780 | 1,840 | 1,830 | 2,011 | 2,096 | 1.1% | 0.9% |
| **JCPL** | 5,770 | 5,780 | 5,740 | 6,349 | 6,607 | 1.1% | 0.9% |
| **METED** | 2,780 | 2,770 | 2,800 | 3,028 | 3,191 | 1.3% | 1.2% |
| **PECO** | 7,990 | 8,090 | 8,060 | 8,769 | 9,101 | 1.1% | 0.9% |
| **PENLC** | 2,850 | 2,820 | 2,870 | 2,991 | 3,147 | 1.4% | 1.2% |
| **PEPCO** | 6,160 | 6,130 | 5,910 | 6,614 | 6,781 | 0.7% | 0.6% |
| **PL** | 6,810 | 6,750 | 6,770 | 7,215 | 7,478 | 0.9% | 0.8% |
| **PS** | 9,540 | 9,480 | 9,490 | 10,275 | 10,533 | 0.7% | 0.6% |
| **RECO** | 395 | 395 | 385 | 416 | 423 | 0.5 % | 0.4% |
| **UGI** | 195 | 190 | 190 | 198 | 204 | 0.9% | 0.8% |
| **VEPCO** | 17,990 | 18,360 | 18,350 | 21,295 | 22,868 | 2.0% | 1.7% |
| **RTO** | 149,400 | 150,105 | 150,295 | 164,443 | 171,579 | 1.1% | 1.0% |

On an interregional basis, regional power flows are rolled up into an Eastern Interconnection model without modification to the regional loads. These power flows are used as starting points for a wide variety of studies and analyses. The entities performing the studies are responsible for any modifications to the power flows or load profiles.

### PowerSouth Energy Cooperative

PowerSouth (a Georgia Transmission [G&T] Cooperative) receives load data from each of its member-owner distribution cooperatives. The data are then manipulated into a coincident peak number for PowerSouth's area. The load forecasts contained in the 2025 roll ups were developed in 2015 on the basis of 2015 to 2020 data. The current load forecast for 2015 to 2020 is expected to increase annually at a 1.09% rate and at a 0.69% rate from 2020 to 2025.

### Santee Cooper

Santee Cooper prepared the load forecast used in the EIPC roll-up model in conjunction with Central Electric Power Cooperative, Inc. staff and a consulting firm. The load forecast is for a coincident peak and incorporates updates of the end-use/econometric models developed by the consulting firm on the basis of normal weather assumptions. The forecast uses historical data and a current economic outlook for Santee Cooper's service areas. The load forecast used in the 2025S roll-up case has a peak of 5,279 MW, representing a 0.40% growth rate from 2014. The 2025W roll-up case peak load of 5,834 MW represents a 0.76% growth rate from 2014.

### South Carolina Electric and Gas

The average annual load growth provided by the LSEs within the South Carolina Electric and Gas (SCE&G) planning area is 1.02% for 2025S and 1.01% for 2025W. This load growth results in a projected peak load of 5,747 MW in 2025S and 5,310 MW in 2025W, including load and transmission losses. The load forecasts contained in the 2025 roll-up cases were developed in 2015 and are based on 2015 assumptions, data, and information. The LSEs within the SCE&G planning area use historical normal weather patterns and various econometric models in determining peak demand forecasts. Each individual LSE develops a forecast that accounts for the individual peak demand forecast. These individual forecasts are then summed to aggregate them into a SCE&G non-coincident forecast.

### Southern Company

The 10-year load growth provided by the LSEs (non-coincident) within the Southern Balancing Authority averaged 1.35% for 2016 through 2025, totaling to a projected load of 52,438 MW in 2025S and 49,630 MW in 2025W.

### Southwest Power Pool

The average forecasted annual load growth provided by the Southwest Power Pool (SPP) members is 1.04% for 2015 through 2025, which results in a projected non-coincident load of 61,635 MW in 2025S and 48,139 MW in 2025W. The load forecasts contained in the 2025S and 2025W roll-up cases were developed in 2014 on the basis of 2014 actuals.

### Tennessee Valley Authority

The load forecast used in the roll-up integration case used Tennessee Valley Authority's (TVA's) official February 2015 delivery point load forecast provided by TVA's Enterprise Planning group. This forecast is a coincident system peak forecast assuming normal weather patterns and a medium economic outlook. This load forecast is a 50/50 load projection where the chance that the actual load will be higher or lower than the forecast is 50%. TVA's load forecasts are 31,600 MW for the 2015 summer peak and 35,040 MW for the 2025 summer peak. This reflects a 1.01% load growth over the next 10 years.

TVA's load forecast for the 2015/2016 winter peak is 31,640 MW and 34,710 MW for the 2015/2016 winter peak. This also reflects a 1.01% load growth over the next 10 years.

## 2.2 Treatment of Energy Efficiency and Demand-Side Resources

This section details the modeling of energy-efficiency programs and demand-side resources in the EIPC roll-up integration case.[7] Because the programs among the jurisdictions differ, the amount and treatment in the power-flow model of energy efficiency or demand resources varies within each Planning Authority. Some planning authorities consider the effects of energy efficiency and demand-side-resource programs when developing their load forecasts, as discussed in Section 2.1. Other planning authorities use market mechanisms to treat energy efficiency and demand-side resources as energy resources.

While treatment of these programs varies across PAs, it is important to realize that some PAs do not net these demand impacts from the gross demand forecasts used in transmission planning models. The PAs recognize that demand-side resources are an important and evolving element to be considered in transmission planning. Regional differences that include market mechanisms for, penetration of, and behavior of demand-side resources dictate the differing treatments of these resources in the PAs' planning analyses. As such, the load forecasts in the transmission planning model may be expected to differ from those developed for resource requirement planning.

For clarity, the summaries below that contain "included," incorporated," "reflected," or "accounted for" to describe the forecasts or modeled load for the individual PAs cases already reflect reductions for the effects of energy efficiency and demand-side resources.

### Duke Energy Carolinas

Energy-efficiency efforts, as required to meet state requirements, have been incorporated into the load in the case. Efficiency efforts constitute an approximate reduction of 912 MW in 2025S and 740 MW in 2025W of load modeled. The modeled load did not include the impact of the application of demand-side management (DSM).

### Duke Energy Florida

DEF has developed energy efficiency and DSM programs, estimated to total 1,903 MW for 2025, as required to meet state requirements. The cases do not model energy efficiency and DSM reductions.

### Duke Energy Progress

Energy-efficiency efforts, as required to meet state requirements, have been incorporated into the load in the case. Efficiency efforts constitute an approximate reduction of 4,677 MW in 2025S and 385 MW in 2025W of load modeled. The modeled load did not include the impact of the application of DSM.

### Electric Energy Inc.

Because Electric Energy Inc. has no native load, a load forecast is not compiled. Energy efficiency and DSM are not applicable.

[7] Demand-side resources include a variety of programs and resources, such as direct load control, dispersed generation, passive and active demand resources, demand-side management (DSM) and other measures.

### Florida Power and Light

The load forecast factors in the impact of higher energy efficiency based on the new 2005 and 2007 federal standards for lighting and appliances. The estimated summer peak demand in the 2025 model will be approximately 1,484 MW lower than it would have otherwise been absent energy efficiency. The impact of the application of DSM is not included in the modeled load.

### Georgia Transmission Corporation

All demand-side management and energy-efficiency programs are under the direction of GTC's individual member cooperatives. GTC does not administer any demand-side management or energy-efficiency programs. The load forecast is based on actual measured load, and the historical usage of load management (LM) and dispersed generation are added back into the annual results to represent total customer load. The load forecast incorporates the impacts of any energy-efficiency programs GTC's member cooperatives use.

### Independent Electricity System Operator

IESO is overseeing the conservation and demand management programs in Ontario and provides projections of long-term peak-demand reduction due to those programs. The aggregation of energy efficiency and demand-side programs included in the load forecast for 2025 is 2,340 MW. These include energy conservation, fuel substitution, and changes in electricity consumption patterns due to the introduction of time-of-use rates at the residential level.

### ISO New England

Energy-efficiency measures that have cleared in the most recent Forward Capacity Auction (2015 FCA #9 for the June 1, 2018, to May 31, 2019, commitment period), including energy-efficiency forecasts, have been incorporated into the load in the model. For summer 2025, a total of 3,535 MW of passive demand resources/energy efficiency (on peak and seasonal peak) and 382 MW of active demand resources/demand-side management (real-time demand resources) were included for a total of 3,917 MW. For winter 2025, a total of 3,403 MW of passive demand resources/energy efficiency (on peak and seasonal peak) and 979 MW of active demand resources/demand-side management (real-time demand resources) were included for a total of 4,011 MW.

### JEA

No planned incremental energy-efficiency programs are represented in JEA's demand forecast in the roll-up integration case. However, JEA's demand forecast does include a historical trend of applied energy-efficiency improvements that have naturally occurred in the market place. Concerning load management and interruptible rate subscribers, JEA does not currently reduce the peak demand in developing the load flow models. Today, JEA's forecasted peak demand reductions from energy efficiency programs, load management programs, and interruptible rate subscribers have not reached a level warranting consideration in transmission capacity avoidance benefits.

### LG&E and KU Energy

All load-serving entities on the LG&E and KU transmission system provide annual load forecasts of the network load levels. The balancing authority forecasted coincident load in the 2025S EIPC roll-up case is 7,745 MW and 6,606 MW for the 2025W EIPC roll-up case.

The LG&E and KU's native LSE load level is based on a 50/50 forecast with all curtailable loads being served. The native load forecast was developed in fall 2014 on the basis of 2014 summer and 2013 winter actual loads. The LG&E and KU native LSE expects an average growth rate of approximately 1.0% from 2015 through 2025. The LG&E and KU native LSE load forecasts in the EIPC 2025 models for summer and winter reflect a reduction in load of 480 MW and 238 MW, respectively, as a result of energy-efficiency programs and demand-side management resources.

### MEAG Power

All demand-side management and energy-efficiency programs are under the direction of MEAG's individual member participants. MEAG does not administer any demand-side management or energy-efficiency programs. The load forecast is based on actual measured load, and historical usage of load management and dispersed generation are added back into the annual results to represent total customer load. The load forecast incorporates the impacts of any energy-efficiency programs used by MEAG's member participants.

### Midcontinent ISO

MISO member systems perform their own load forecasting and provide the load projections for the planning horizon power-flow models. The load projections include adjustments for energy efficiency and demand-side measures consistent with the local transmission planning practices of each member system. The demand projections in the 2025 power-flow cases for the MISO portion of the roll-up integration case are consistent with the MISO section of the NERC *2015 Long Term Resource Assessment Report*.

### New York ISO

Energy efficiency and solar photovoltaic (PV) impacts for state-mandated programs are included in the NYISO's load forecasts. For 2020, the summer peak load forecast includes a reduction of 1,981 MW for these programs. By 2025, the reduction in summer peak demand from energy efficiency and solar PV programs is 2,738 MW. Impacts of demand-side programs (e.g., demand response) are not included in the forecasted load. Interruptible load and distributed generation resources of 1,124 MW (referred to as *special-case resource*s in New York) are not included in the load forecast because they are treated as a capacity resource.

### PJM Interconnection

Load management and energy efficiency (LM and EE) resources have been incorporated into the load forecast report based on amounts cleared in PJM markets for delivery years through 2015. The 2015 values are used as assumptions throughout the forecast horizon. Projections for changes to LM and EE past 2015 are not currently factored into the forecasts, although changes to this procedure are under consideration. PJM's planning power-flow models appropriately modify the loads or generation models for LM and EE resources, depending on the type of planning analysis being performed. The loads in the 2020 and 2025 roll-up power-flow case are based on unrestricted peaks, which mean that they are not adjusted for LM and EE. For 2025 summer, EE and demand response constitute an approximate equivalent reduction of 1,233 MW and 11,102 MW, respectively, for a total of 12,335 MW. Based on actual operations experience, the load management PJM calls on is fully available but limited in the number times it can be used. Refer to the references in Section 2.1 for more details regarding PJM's LM and EE measures.

### PowerSouth Energy Cooperative

The PowerSouth load forecast for 2025S reflects a reduction in load of 4.9 MW and 11 MW for 2025W as a result of energy demand-side management resources (a water heater program). DSM is projected to be 9 MW in 2023. These reductions are reflected in PowerSouth's net peak load per year.

### Santee Cooper

Santee Cooper prepared the load forecast used in the roll-up integration case in conjunction with Central Electric Power Cooperative, Inc. staff and a consulting firm. The load forecast incorporates updates of the end-use/econometric models developed by the consulting firm and is based on normal weather assumptions. The forecast uses historical data and a current economic outlook for Santee Cooper's service areas. The forecast for industrial customers reflects any additions and changes to existing contracts. The load forecast includes estimated demand and energy savings from future energy-efficiency programs to be implemented by Santee Cooper and Central. The net load forecast used in the 2025S roll-up case has approximately 142 MW of energy efficiency and demand-side management. The 2025W roll-up case has approximately 180,225 MW of EE and DSM.

### South Carolina Electric and Gas

SCE&G is projecting 216 MW of energy-efficiency programs in 2025. All this was reduced from the gross load forecast to produce the net peak load used for the SCE&G system in the EIPC roll-up integration case. SCE&G is projecting 289 MW of demand-side management programs in 2025. None of this was reduced from the gross load forecast to produce the net peak load used for the SCE&G system in the roll-up integration.

### Southern Company

The Southern Company load forecast for 2025 reflects a reduction in load of 1,868 MW as a result of energy-efficiency programs and non-dispatchable (passive) demand-side management resources. Dispatchable (active) demand-side resources or real-time pricing resources are accounted for and considered as part of the resource decisions provided by each load serving entity.

### Southwest Power Pool

SPP members have developed energy efficiency and demand-side management programs, estimated to 2,055 MW for 2025S and 846 MW for 2025W. However, SPP is not currently modeling energy efficiency and demand-side management as a source of load reduction in this model case.

### Tennessee Valley Authority

TVA's demand-side management program primarily focuses on the areas of pricing products and the direct load control of large industrial customers, HVAC equipment, and water heaters. The load forecasts used in determining TVA's transmission expansion plan reflect its energy-efficiency programs. However, TVA does not include the effects of demand-side management in these forecasts because of the difficulty in predicting the specific delivery points that will be affected by these programs.

## 2.3 Interchange or Firm Transmission Service Modeled

This section describes the typical interchange or inter-area energy transfers modeled by each Planning Authority. Appendix E of this report includes interchange data tables. The roll-up integration case includes full-path transactions between areas (imports/exports) (where both the importing and exporting PAs recognize common commitments), but not partial-path transactions, (where arrangements for transmission service have been made with only one party).

### Alcoa Power Generating, Inc.

The 2020 roll-up integration case has no interchange for Alcoa's Yadkin division.

### Duke Energy Carolinas

In the 2025S case, the DEC Balancing Authority has a net export to CPLE of 1,000 MW from independent power producers (IPPs) at Rowan and Broad River Energy Center serving the Duke Energy Progress load, while NCEMC resources in CPLE and DEC are shared between the areas. NCEMC also exports 50 MW of its resources to serve its load in DVP (a part of PJM). PMPA imports 230 MW from Santee Cooper to serve its load in DEC. There are imports of 268 MW from SEPA's generation on the Savannah. The resultant net interchange is an export of 528 MW.

In the 2025W case, the Duke Energy Carolinas BA has a net export to CPLE of 850 MW from Broad River Energy Center serving Duke Energy Progress's load, while 150 MW from Rowan are exported to CPLW. NCEMC resources in CPLE and DEC are shared between the areas. NCEMC also exports 50 MW of its resources to serve its load in DVP (a part of PJM). PMPA imports 124 MW from SCPSA to serve its load in DEC. There are imports of 268 MW from SEPA's generation on the Savannah River. The resultant net interchange is an export of 642 MW.

### Duke Energy Florida

DEF includes confirmed annual firm transmission service requests in accordance with resource projections provided by LSEs and executed contracts for the sale of firm energy. DEF's one balancing area is FPC whose area model includes a net interchange import of 2,695 MW for 2025 summer and 2,940 MW for 2025 winter.

### Duke Energy Progress

DEP includes confirmed annual firm transmission service requests in accordance with LSE resource projections and executed contracts for the sale of firm energy. DEP has two balancing areas, CPLE and CPLW. The CPLE area model includes 1,400 MW of imports and 462 MW of exports, resulting in a net interchange import of 938 MW in 2025S. For 2025W, the CPLE area model includes 1,250 MW of imports and 562 MW of exports, resulting in a net interchange import of 688 MW. The CPLW area model includes 151 MW of imports and no exports, resulting in a net interchange import of 151 MW in 2025S; it has 401 MW of imports and no exports, resulting in a net interchange import of 401 MW in 2025W.

### Electric Energy Inc.

The output of Electric Energy, Inc. generation is modeled as an export to Ameren-Illinois (AMIL).

### Florida Power and Light

The scheduled net interchange modeled for the FPL area reflects the forecasted, firm interchange transactions as coordinated with the other utilities within the Florida Reliability Coordinating Council (FRCC) Region. Approximately 886 MW of imports flow into FPL's BA from inside the FRCC associated with unit ownership or PPAs. Approximately 946 MW of imports flow into FPL's BA from outside the FRCC associated with unit ownership or PPAs.

### Georgia Transmission Corporation

GTC's information is included in the response from Southern Company.

### Independent Electricity System Operator

Transmission service is not sold in Ontario. Transactions at the interties are scheduled on the basis of economic merit through the energy market, and successfully scheduled transactions are provided with access to the transmission system. Therefore, IESO 2020 and 2025 models have zero firm transactions.

IESO area interchange assumptions in the 2020 and 2025 roll-up integration cases include a net import of 1,250 MW from Quebec on high-voltage direct-current (HVDC) lines.

### ISO New England

ISO New England's area interchange assumptions in the 2025S and 2025W roll-up integration cases include 2,607 MW and 2,408 MW of imports, respectively. In each case, 344 MW of exports are also modeled, resulting in a net import of 2,271 MW in 2025S and 429 MW in 2025W. Most of this interchange comes from 1,725 MW imported from Quebec on HVDC lines to northern Vermont and eastern Massachusetts.

### JEA

In addition to JEA's obligation to serve JEA's native retail territorial load, JEA also has contractual obligations to provide transmission service for the transmission-level customer and for delivery of contractual power from jointly owned and independent power producer plants. The transactions included in JEA's load-flow model include all the firm long-term generation and transmission service capacities through 2024. In addition to JEA's territorial system ties supporting import and export capabilities, JEA also has allocation rights in the Florida/Georgia 500 kilovolt (kV) tie import and export capacity. The power interchange used for this study includes 404 MW of imports from Georgia (Southern Company) to JEA and 254 MW of exports from JEA to the FRCC region, with a resultant 148 MW of net power interchange (exports) in the 2025 roll-up integration case.

### LG&E and KU Energy

LG&E and KU's area interchange assumptions in the 2025S roll-up integration case include 309 MW of imports and 310 MW of exports, resulting in a net interchange of 1 MW of exports. LG&E and KU's area interchange assumptions in the 2025W roll-up integration case include 308 MW of imports and 317 MW of exports, resulting in a net interchange of 9 MW of exports. Values represented in Appendix E reflect long-term (one year or more) firm transmission service obligations.

### MEAG Power

MEAG's information is included in the response from Southern Company.

### Midcontinent ISO

For MISO members, internal interchange is based on the market dispatch, and interregional interchange is based on currently known net firm drive-in and drive-out transactions between MISO member control areas and external control areas. The amount of net interchange between MISO and its neighboring planning authorities is unchanged from the corresponding ERAG case. Appendix E contains detailed interchange information. Import and export transactions have been agreed to and are consistent with those of external PA regions.

### New York ISO

The NYISO coordinates its interchange schedule with its neighbors and represents firm transactions and the expected continuance of current external installed capacity (ICAP) providers as listed in the NYISO *2015 Load and Capacity Data Report*.

### PJM Interconnection

PJM's interchange with external systems included in the roll-up integration case model represents long-term firm interchange transactions and non-firm transactions chosen by individual transmission owners. This representation is a snapshot of what may be considered "typical" transactions. It is the agreed-upon basis for assembling the interregional reference cases, according to the Eastern Reliability Assessment Group, Multiregional Modeling Working Group process. Because individual planning authorities must assemble interregional reference cases that interchange with many neighbors, the interchanges are necessarily only starting point values that must be appropriately adjusted, depending on the nature of the planning analysis being performed. The series of annual PJM Regional Transmission Expansion Plan (RTEP) transmission studies plan for firm interchange values between PJM and its neighbors. PJM's net firm interchange with neighbors in the 2020 roll-up model is -6,511 MW (import) non-firm interchanges were not modeled in either case. Interchanges among the areas internal to PJM are the free-flowing result of PJM's single-area market dispatch and do not result from transaction schedules such as the interchanges between PJM and external areas. PJM's planning analyses examine thousands of dispatch scenarios. The internal PJM starting-point interchanges, therefore, are not a focus of PJM planning analyses.

### PowerSouth Energy Cooperative

PowerSouth's area interchange assumptions in the 2025S roll-up integration case include 441 MW of imports and 1,091 MW of exports, resulting in a net interchange of 651 MW. PowerSouth's area interchange assumptions in the 2025W roll-up integration case include 441 MW of imports and 1,248 MW of exports, resulting in a net interchange of 807 MW of exports. The values shown in Appendix E reflect long-term (one year or more) firm transmission service obligations as they relate to the transmission service provider.

### Santee Cooper

The area interchange schedule for the 2025S roll-up integration case includes 1,579 MW of imports and 336 MW exports for a net interchange of 1,309 MW of imports. The 2025W roll-up integration case contains 15,295 MW of imports and 173 MW of exports for a net interchange of 1,356 MW of imports. No firm transmission service requests are modeled in either case.

### South Carolina Electric and Gas

SCE&G's area interchange assumptions in the 2025 roll-up integration case include 62 MW of imports and 256 MW of exports, resulting in a net interchange of 194 MW of exports. The values represented in Appendix E reflect long-term (one year or more) firm transmission service obligations.

### Southern Company

Southern Company's area interchange assumptions in the 2025S roll-up integration case include 2,077 MW of imports and 2,265 MW of exports, resulting in a net interchange of 188 MW of exports. Southern Company's area interchange assumptions in the 2025W roll-up integration case include 2,252 MW of imports and 2,304 MW of exports, resulting in a net interchange of 52 MW of exports. The values represented in Appendix E reflect long-term (one year or more) firm transmission service obligations.

### Southwest Power Pool

SPP's area interchange assumptions in the 2025S roll-up integration case include 4,903 MW of imports and 4,672 MW of exports, resulting in a net interchange of 231 MW of imports. The 2025W roll-up integration case includes 3,769 MW of imports and 3,438 MW of exports, resulting in a net interchange of 331 MW of imports. SPP includes long-term firm transmission service requests in models, as well as related projects with an approved FERC-filed Notification to Construct (NTC). Appendix E shows the amount of net interchange between SPP and its neighboring planning authorities.

### Tennessee Valley Authority

TVA's area interchange assumptions in the 2025 summer roll-up integration case include 1,090 MW of imports and 1,188 MW of exports, resulting in a net interchange of 98 MW of exports. The values represented in Appendix E reflect long-term (one year or more) firm transmission service obligations.

TVA's area interchange assumptions in the 2025/26 winter roll-up integration case include 1,129 MW of imports and 1,155 MW of exports, resulting in a net interchange of 26 MW of exports. The values represented in Appendix E reflect long-term (one year or more) firm transmission service obligations.

## 2.4 Process for Future Transmission Project Inclusion

The section describes each Planning Authority's planning process for inclusion of new transmission projects. The tables in Appendix B provide a complete, detailed listing of all new and upgraded transmission projects included in the 2025S and 2025W roll-up integration cases. The "Projected

In-Service Date" column in these tables indicates whether the facility was included in the 2025S and 2025W models (2025S) or just the 2025W model (2025W Since the inclusion of transmission projects varies based on each PA's process, the PAs have agreed to the following terms for describing the status of future projects, which are used in Appendix B:

- **Construction**—project is under construction.
- **Committed**—project has obtained some level of contractual obligation or regulatory approval or is included in approved capital budgets.
- **Planned**—project has completed the respective Planning Authority's planning process, including obtaining any applicable regional planning process approvals (for example, ISO or RTO approvals), but specific contractual obligations have not been committed to, or regulatory approvals obtained.
- **Proposed**—project has been proposed but has not yet completed the respective Planning Authority's planning process or received applicable regional planning process approvals. In this case, the year of the expected completion of the process and applicable regional approval is listed in Appendix B.
- **Conceptual**—project has been identified as a potential solution to a constraint identified during the validation process for the EIPC roll-up model. The project and constraint have not previously been identified during the Planning Authority's normal planning process.
- **On Hold**—project has been withdrawn or suspended.

### Alcoa Power Generating, Inc.

Alcoa's Yadkin division has no plans for future generation or transmission expansions.

### Duke Energy Carolinas

Transmission planning performed by DEC is a continuous process. This continuous transmission planning process consists of (1) internal screening and analysis, (2) coordinated studies with neighboring systems, and (3) the development of a collaborative transmission plan with Duke Energy Progress under the North Carolina Transmission Planning Collaborative. The result of these efforts is the identification of projects to upgrade existing facilities or the addition of new facilities needed to meet DEC's transmission planning criteria and NERC Reliability Standards.

Transmission facilities approved and budgeted or where construction has begun have been included in the 2025 summer and winter cases. Other projects the planners believe have a high certainty of being in service in the year being modeled are also included. Engineering judgment has been applied such that a new or upgraded facility marginally necessary may not have been included in the base model so that the timing of the need for the facility can be accurately determined.

### Duke Energy Florida

DEF's transmission expansion plan is the compilation of transmission facility improvements and upgrades necessary for the transmission system to support the proposed resource assumptions, load forecasts, and firm transmission service requirements for the next 10 years in the most reliable and economic manner consistent with NERC Reliability Standards. The expansion plan is based on information obtained through DEF's internal planning efforts and FERC's Order 890 Attachment K process, as well as through the FRCC long-range study assessments and other joint studies with interconnected neighbors. Transmission facilities that are approved, committed, and budgeted or where construction has begun are included in the case. Other projects the planners believe have a high certainty of being in service in the year being modeled are also included. Most transmission projects are included to meet first-contingency (N-1) criteria; however, some projects are included to meet credible second-contingency (N-2) criteria where there is no operating solution or acceptable special protection system to resolve.

### Duke Energy Progress

DEP's transmission expansion plan is the compilation of transmission facility improvements and upgrades necessary for the transmission system to support the proposed resource assumptions, load forecasts, and firm transmission service requirements for the next 10 years in the most reliable and economic manner consistent with NERC Reliability Standards. The expansion plan is based on information obtained through Progress Energy Carolina's (PEC's) internal planning efforts as well as through the SERC Long-Term Study Group, North Carolina Transmission Planning Collaborative, Southeastern Interregional Participation Process, and joint studies with interconnected neighbors. Approved, committed, and budgeted transmission facilities, or those for which construction has begun, are included in the models. Other projects the planners believe have a high certainty of being in service in the year being modeled are also included. Engineering judgment is applied such that a new or upgraded facility marginally needed may not be included in the base model so that the timing of the need for the facility can be accurately determined. Projects are included to meet N-1 contingency criteria. Additionally, projects that have not been through the state certification process could potentially be included, but this is not the case for the 2025 roll-up integration cases used in this process.

### Electric Energy Inc.

Electric Energy, Inc. (through the services of consulting companies) annually analyzes its transmission system response to generation and transmission system expansion plans and its expected power purchases and those of other entities through short-term and long-range transmission planning studies. The objective of Electric Energy, Inc. is to provide adequate electrical capacity and transfer capability to serve its customers with acceptable reliability, commensurate with cost. Historically, the Paducah Gaseous Diffusion Plant (PGDP) is the major customer for Electric Energy, Inc. The general approach to planning is to provide adequate and sufficiently reliable transmission capability for the generating plant outlet to ensure that the needs of the PGDP are satisfied. It must also ensure that during periods of light PGDP load, Electric Energy, Inc. has sufficient transmission transfer capability to export the full generation capacity.

### Florida Power and Light

The role-up integration case includes future projects that have undergone FPL's internal budget review process, as well as those projects representative of the *Ten-Year Site Plan* (TYSP) filing with the Florida Public Service Commission.

### Georgia Transmission Corporation

GTC performs transmission planning studies on a continuous basis to identify needed transmission improvements. These studies identify transmission improvement projects required to support the load- serving needs of GTC's member cooperatives and GTC's long-term firm transmission tariff customers. GTC also identifies projects to interconnect new generation, as applicable. To jointly plan for future transmission expansion, GTC reviews and coordinates study recommendations with other transmission owners in Georgia. GTC also reviews study work performed by other transmission owners in Georgia and coordinates with utilities in surrounding regions. The role-up integration case includes transmission improvement projects in GTC's expansion plans.

### Independent Electricity System Operator

Planning in Ontario is conducted on two fronts: assessing future system conditions with known and expected facilities in place and developing future plans on resources and transmission to meet the needs of the system. Both processes use applicable NERC Reliability Standards and NPCC regional Reliability Standards to evaluate the reliability performance of the proposed projects.

As the Planning Authority, IESO conducts transmission and resource adequacy assessments as follows:

- An Ontario Reliability Outlook with a five-year horizon, issued as required
- An 18-Month Outlook Update conducted semiannually
- A Review of Resource Adequacy with a five-year horizon, submitted annually to the Northeast Power Coordinating Council (NPCC)
- A Review of Transmission Adequacy with a five-year horizon, submitted annually to NPCC

These assessments of future conditions, such as system constraints and resource adequacy, are based on planned system conditions; they do not propose resource or transmission plans to meet adequacy needs or to alleviate system constraints. Market participants use these reports for making investment decisions regarding power system assets.

The Power System Planning (PSP) department in IESO, the former Ontario Power Authority (OPA), addresses long-term system planning through an independent and integrated plan for conservation, generation, and transmission over a 20-year period.

Through PSP's planning activities, the PSP identifies resource and transmission requirements, procures resources, and promotes conservation, as required to ensure supply adequacy and respond to other system and policy needs. Transmission owners develop options to meet the transmission facility proposals, such as route selections, line types, and associated facilities. Through the System Impact Assessment (SIA) process, IESO evaluates the system performance of these options under forecast system conditions and when subjected to various contingencies.

The applicable seasonal peak power-flow models that IESO develops annually for MMWG is available in the most recent NERC ERAG Model series. The models have been updated to include all future transmission and generation projects in Ontario that passed the IESO Connection

Assessment and Approval (CAA) process, along with any upgrades required to maintain the reliability of the IESO system, including future transmission and generation.

### ISO New England

ISO New England's portion of the 2025 roll-up integration cases include all future projects approved under Section I.3.9 of the ISO New England tariff.[8] Pursuant to Section I.3.9, the ISO reviews proposals for new generation and transmission facilities rated at or above 69 kV. If the ISO determines that a project would have no significant adverse impacts on the stability, reliability, or operating characteristics of existing electrical infrastructure, it approves the project for interconnection to the grid. Projects that have reached this stage are assumed to be in service for the 2025 roll-up cases.

In the case of transmission projects, projects submitted for review pursuant to Section I.3.9 are those which are being developed and generally supported as part of the New England regional transmission planning process.

### JEA

JEA does not include in its load-flow models any transmission projects categorized in this report as "proposed." All projects sponsored by JEA in the roll-up integration cases have the status of "state/budget approval" (categorized in this report as "committed"). JEA's policy and practice is to include in the load-flow transmission model only those committed projects (e.g., facility additions, modifications, retirements, or system topology changes) whose inclusion represents the most probable future scenario. To JEA, this means that a project has, at a minimum, undergone its internal budget review process and has been approved for real estate activities associated with securing rights-of-ways (ROWs) or has been accepted in the capital budget process for legally appropriated funding in the upcoming fiscal year. However, JEA may decide not to add a project to the load-flow models until real estate has been properly secured or the project has a high probability of being successfully acquired.

### LG&E and KU Energy

The primary purpose of LG&E/KU's transmission system is to reliably transmit electric energy from network resources to network loads. LG&E/KU has established Transmission Planning Guidelines to gauge the adequacy of the transmission system to supply projected network customer demand and contracted long-term, firm, point-to-point (PTP) transmission services. The process is an annual cycle designed to incorporate external network changes and to provide information for regional evaluation and coordination through the NERC ERAG model-building process.

LG&E/KU develops seasonal peak power-flow models annually (first quarter) using each model year available in the most recent NERC ERAG model series. The topology of the LG&E/KU transmission system is expanded to provide a more detailed representation of the 69 kV facilities and is updated to reflect the current Transmission Expansion Plan. Network resources and network loads are updated to reflect the most recent information from the network customers. Seasonal

---

[8] The *ISO New England Transmission, Markets, and Services Tariff* is available at http://iso-ne.com/participate/rules-procedures/tariff.

peak cases may also be developed without certain generators or major transmission additions to improve the models and their interpolation between model years.

The Transmission Expansion Plan is evaluated and updated through screening, verification, area studies, facility studies, signed agreements, and other periodic studies, as described below:

- **Screening**—Generator and transmission contingencies are simulated on the base cases to identify overloads and low voltages not resolved by the Transmission Expansion Plan.
- **Verification**—Projects in the Transmission Expansion Plan and issues identified in the screening are evaluated to determine the required upgrade or construction and completion date and to identify the reason for the change. The required completion date is determined by interpolating flows between model years.
- **Area Studies**—Area studies are performed before major construction to develop multiple long-term options that provide adequate transmission through the planning period. The least-cost option is recommended for approval, and the associated projects are incorporated into the Transmission Expansion Plan.
- **Facility Studies**—Facility studies are performed following a request made by customers through the Independent Transmission Organization (ITO) by a network-integrated transmission service (NITS), designated network resource (DNR), or point-to-point request. The ITO provides the customers multiple options with associated costs and time frames for completing construction of the requested service.
- **Signed Agreements**—Construction and upgrades associated with generator interconnections, transmission-to-transmission interconnections, and network service requests executed by the requestor, which have been submitted to and evaluated by the ITO and LG&E and KU in the previous year, are incorporated into the Transmission Expansion Plan.

Generator and transmission contingencies are routinely simulated to evaluate the adequacy of the transmission system in meeting the “no loss-of-demand or curtailment of firm-transfer” requirements of the Transmission Planning Guidelines.

Periodic studies evaluate the adequacy of the LG&E/KU transmission system in meeting the allowable loss-of-demand or curtailment of firm-transfer requirements and system stability.” The Transmission Expansion Plan incorporates the necessary construction and upgrades identified by these studies.

Annually, the LG&E and KU Transmission Expansion Plan is submitted to the ITO and RC for independent review, evaluation, and comment regarding any outstanding issues that should be addressed. The ITO must approve the final plan developed by the transmission owner.

### MEAG Power

MEAG performs transmission planning studies on a continuous basis to identify transmission improvements required to support the load-serving needs of its participants and long-term firm transmission tariff customers. MEAG also identifies projects to interconnect new generation, as applicable. To jointly plan for future transmission expansion, MEAG reviews and coordinates study recommendations with other transmission owners in Georgia. MEAG also reviews study work performed by other transmission owners in Georgia and coordinates with utilities in surrounding regions. Transmission improvement projects included in MEAG's expansion plans were included in the roll-up integration case.

### Midcontinent ISO

MISO produces a MISO Transmission Expansion Plan annually. This regional plan is produced in collaboration with transmission-owning members, using a stakeholder process compliant with FERC Order 890. The regional plan, once approved by the MISO Board of Directors, represents the recommended plan for the region. The member transmission owners are bound by formal agreement to use a good-faith effort to obtain all necessary state and local approvals and to construct the projects so approved for regional implementation.

The criteria applied by MISO for including projects in the roll-up integration case was to include all transmission projects in the agreed-on EIPC status categories of planned, proposed, or conceptual. MISO included proposed projects pending approval in the MTEP15 planning cycle, which began September 2014 and concluded with board approval December 2015.

### New York ISO

The NYISO Comprehensive System Planning Process (CSPP) comprises four components:

- Local Transmission Planning Process (LTPP)
- Reliability Planning Process (RPP)
- Economic Planning Process (EPP)
- Public Policy Transmission Planning Process (PPTPP)

Under the LTPP, the local transmission owners perform transmission studies for their transmission areas according to all applicable criteria. This includes identifying and evaluating solutions to local transmission needs driven by public policy requirements. This process produces the Local Transmission Owner Plan (LTP), which feeds into the NYISO's determination of system needs through the CSPP.

The requirements of the Reliability Planning Process are described in the RPP Manual and Attachment Y of the OATT. Under this biennial process, the reliability of the New York bulk power system is assessed; any reliability needs are identified; solutions to identified needs are proposed and evaluated for their viability and sufficiency to satisfy the identified needs; and the more efficient or cost-effective transmission solution to the identified needs, if any, is selected by the NYISO. This process was originally developed and implemented in conjunction with stakeholders; it was approved by FERC in December 2004 and revised in 2014 to conform to FERC Order No. 1000. The RPP consists of two studies:

1. The *Reliability Needs Assessment* (RNA): The NYISO performs a biennial study to evaluate the resource adequacy and transmission system adequacy and security of the New York bulk power system over a 10-year study period. Through this evaluation, the NYISO

identifies reliability needs in accordance with applicable reliability criteria. This report is reviewed by NYISO stakeholders and approved by the board of directors.

2. The *Comprehensive Reliability Plan* (CRP): After the RNA is complete, the NYISO requests the submission of market-based solutions to satisfy the identified Reliability Needs. The NYISO also identifies a Responsible TO and requests that the Responsible TO submit a regulated backstop solution and that any interested entities submit alternative regulated solutions to address the identified reliability needs. The NYISO evaluates the viability and sufficiency of the proposed solutions to satisfy the identified reliability needs and evaluates and selects the more efficient or cost-effective transmission solution to the identified need. If a market-based solution does not materialize to meet a reliability need in a timely manner, the NYISO triggers a regulated solution(s) to satisfy the need. The NYISO develops the CRP for the 10-year study period and sets forth its findings regarding the proposed solutions. The CRP is reviewed by NYISO stakeholders and approved by the board of directors.

The third component of the CSPP is the Economic Planning Process. The *Congestion Assessment and Resource Integration Study* (CARIS) examines congestion on the New York bulk power system and the costs and benefits of generic alternatives to alleviate that congestion. In Phase 2 of CARIS, the NYISO evaluates specific transmission project proposals for regulated cost recovery.

The fourth component of the CSPP is the Public Policy Transmission Planning Process. Under this process, interested entities propose, and the New York State Public Service Commission (NYPSC) identifies, transmission needs driven by public policy requirements. The NYISO tariff defines a public policy requirement as a federal or state law or regulation that drives the need for transmission. These laws include an NYPSC rulemaking order adopted after public notice and comment under state law. The NYISO then requests that interested entities submit proposed solutions to address the identified public policy transmission needs. The NYISO evaluates the viability and sufficiency of the proposed solutions to satisfy each identified public policy transmission need. The NYISO then evaluates and may select the more efficient or cost-effective transmission solution to each identified need. The NYISO develops the *Public Policy Transmission Planning Report* that sets forth its findings regarding the proposed solutions. NYISO stakeholders review this report, and the board of directors approves it.

In concert with these four components, interregional planning is conducted with the NYISO's neighboring control areas in the United States and Canada under the Northeastern ISO/RTO Planning Coordination Protocol. The NYISO participates in interregional planning and may consider interregional transmission projects in its regional planning processes.

### PJM Interconnection

PJM's annual Regional Transmission Expansion Plan process comprehensively examines the transmission system requirements to ensure the reliability, economy, competitiveness, and comparability of service under the PJM tariffs and agreements. PJM is the single Planning Authority, transmission planner, reliability authority, and balancing authority for the RTO. The RTEP process first identifies transmission system upgrades and enhancements to preserve grid reliability, the foundation of competitive wholesale power markets. The annual series of RTEP analysis also includes planning for market efficiency that (1) advances planned reliability projects when the economic benefit is sufficient, (2) provides new projects that have sufficient market efficiency benefits to justify their expense, and (3) combines reliability and market efficiency projects when benefits are sufficient to justify added expenditures. A third facet of PJM planning is annually reviewing system operational performance, evaluating any issues, and planning beneficial system upgrades. In addition, PJM tariffs and agreements also provide for interregional upgrades resulting from periodic interregional reviews. This annual series of analyses produces the PJM baseline RTEP system. This system forms the foundation for the incremental assessment of queued requests for interconnection to the transmission system. PJM planning conducts a queue process that sequentially evaluates interconnection requests to determine incremental transmission upgrades necessary for their reliable interconnection and operation with the system.

In addition, pursuant to process enhancements put in place in response to FERC Order No. 1000, PJM plans for public policy transmission needs. Transmission enhancements required to facilitate public policy agreed to by the states and adopted in the PJM RTEP become part of the PJM transmission plans. Also, pursuant to Order 1000 interregional enhancements, PJM is beginning assessments of neighboring transmission plans on its borders to determine more efficient and cost-effective interregional plans that may replace separate regional plans.

This series of RTEP analysis is based on maintaining reliability, market efficiency, and operational performance for committed uses of the system and reasonably anticipated load growth and new interconnections. The system is planned for new generation with signed Interconnection Service Agreements or signed Facility Study Agreements.

The recommended transmission upgrades resulting from this series of analyses are subject to ongoing review and input with PJM's stakeholders through the PJM committee process. The resulting RTEP projects are presented to the PJM independent board of managers periodically throughout the year for approval. RTEP-approved projects are cost allocated, assigned for construction, and proceed from planning into the project tracking and construction phase. At this point, entities assigned construction responsibility engage necessary design, siting, and regulatory approval processes. PJM supports the need justification for projects as necessary throughout regulatory approvals.

The PJM RTEP process is ongoing. PJM's reference transmission case changes continuously as new needed RTEP upgrades are identified. At any point in time the PJM reference RTEP power flow includes predominately existing and planned, board-approved facilities. PJM planning only tracks and reports state regulatory approval status of the major "backbone" projects. The PJM reference power flow typically has some very recent necessary upgrades scheduled for approval at the next regularly scheduled board meeting. These most often address recently identified RTEP baseline or queue project issues that surface in the continuous stream of analysis. The projects pending board approval are represented as "proposed" in the PJM list of upgrades. Such projects typically become board approved within months; therefore, for PJM, the "proposed" project label does not represent a material difference from "planned" facilities with regard to the "certainty" of the transmission projects going forward. All the listed PJM projects are required for system reliability by the specified dates and are very likely to proceed. The "certainty" of projects coupled with new interconnection requests, naturally, are linked to the business plans of the interconnection customer. The progress of all projects is tracked, and alternate plans or temporary mitigation actions are developed when issues may delay a project's completion. PJM's RTEP process includes both five-year and 15-year assessments to meet all applicable reliability planning criteria. The applicable reliability planning criteria include the following:

- NERC Planning Standards
- RFC Reliability Principles and Standards
- PJM Reliability Planning Criteria as contained in Manual M14 Attachment G[9]
- Transmission Owner Reliability Planning Criteria. as filed in their respective FERC 715 filing

Five-year-out planning enables PJM to assess and recommend transmission upgrades to meet forecasted load growth and to ensure the safe and reliable interconnection of new generation and merchant transmission projects seeking interconnection within PJM. The 15-year planning horizon for PJM allows for the consideration of many long-lead-time transmission options. These options often comprise larger-magnitude transmission facilities that more efficiently and globally address reliability issues. Typically, these are higher-voltage upgrades that simultaneously address multiple NERC reliability criteria violations at all voltage levels. A 15-year horizon also allows PJM to consider the aggregate effects of many system trends, including long-term load growth, impacts of generation deactivation, and broader generation development patterns across PJM.

### PowerSouth Energy Cooperative

PowerSouth's transmission planning is a yearly, continuous process based on a rolling 10-year cycle that identifies needed enhancements to the existing transmission system. PowerSouth coordinates with Southern Company and South Mississippi Electric Power Association (SMEPA) to accurately model shared ownership resources, as well as area interchange values. PowerSouth also submits data to and participates in SERC's Long-Term Study Group (LTSG), which helps create the MMWG models. Projects included in the model can be member driven (i.e., new delivery point), reliability driven (new bulk transmission), as related to the NERC standards, or any combination. PowerSouth, as a G&T Cooperative, is not under any state regulation authority. New transmission and generation projects are vetted through a board-approval process.

### Santee Cooper

Santee Cooper produces a 10-year transmission plan on an annual basis. The criteria for including projects in the roll-up model are to include future projects budgeted and approved for implementation by executive management. Planned and uncommitted construction projects are also included in the model but only if the project is judged to be well defined and most likely to be fully implemented. Results of assessments are used to determine whether the current construction schedule of planned transmission facilities should be altered to reflect future system requirements. Proposed additions identified and verified throughout the assessment will be incorporated with a recommended schedule, as needed.

### South Carolina Electric and Gas

SCE&G includes in its transmission models all transmission projects budgeted and approved to be included in the transmission expansion plan. Not all projects have a commitment to build because they are reviewed for need and modifications on an ongoing basis through the annual and iterative transmission planning process. These reviews occur in the form of transmission system

---

[9] This PJM manual is available at http://www.pjm.com/documents/manuals.aspx.

assessments with and without these transmission improvements and reflect changes in assumptions and objectives of the transmission system based on LSE needs, transmission service commitments, and resource interconnections. Transmission projects in SCE&G's transmission expansion plan and in the EIPC roll-up case include (1) projects required to meet NERC Reliability Standards and SCE&G Transmission Planning Criteria, (2) projects required for the provision of firm transmission service (network and point-to-point), per the SCE&G OATT, and (3) system upgrades associated with generator interconnections, per the SCE&G OATT.

### Southern Company

On a continuous, iterative basis, 10-year transmission expansion plans are developed to support load-serving entities and other long-term firm transmission customers under the *Open Access Transmission Tariff* in delivering energy on a firm basis. Transmission projects in Southern Company's expansion plans and in the roll-up include the following:

- Projects to meet long-term firm service commitments of LSEs and point-to-point transmission customers
- Projects to interconnect new generation customers who have signed interconnection agreements
- For periods later in the 10-year planning horizon, projects associated with network reservations provided by LSEs for generation capacity necessary to meet their respective load obligations

As transmission projects are identified, the requirements of state law are followed to obtain any requisite approvals to move forward with these projects. The level of formality varies within each of the different jurisdictions. If the need for the transmission project is attributable to the planned addition of a supply-side resource, the approval for that project is generally sought in the certification proceeding for that resource. Additionally, the states also vary with regard to which transmission projects must receive specific state certification approvals.

### Southwest Power Pool

The Integrated Transmission Plan (ITP) is SPP's approach to planning transmission needed to maintain reliability, provide economic benefits, and achieve public policy goals in both the near and long terms. The ITP enables SPP and its stakeholders to facilitate the development of a robust transmission grid that improves customers' access to the SPP region's diverse resources.

The ITP is an iterative three-year process that includes 20-year, 10-year, and near-term assessments. The results of these assessments guide what SPP transmission projects are included in the base case. Projects resulting from the ITP that receive a Notification to Construct are included in the base case. Additionally, projects can receive an NTC from the Generation Interconnection and Aggregate Service Request study processes. These projects are also included in the base case.

### Tennessee Valley Authority

TVA develops a 10-year transmission expansion plan on an annual basis. The plan supports the firm delivery of energy on the basis of the projected load forecasts for the TVA Balancing Authority (BA) area as well as other long-term firm transmission service customers under the TVA OATT.

Transmission projects in TVA's expansion plans and in the roll-up include the following types of projects:

- Projects associated with network reservations for generation capacity necessary to meet system load obligations
- Projects to meet long-term firm point-to-point transmission service commitments of transmission customers
- Projects to interconnect new generation customers

As a federal entity, TVA follows the requirements of the *National Environmental Policy Act* (NEPA) to move forward with identified transmission projects.[10] The approval for a transmission project needed as a result of the planned addition of a supply-side resource is obtained through the process for that resource. Planned system modifications are included in TVA's transmission expansion plan as the transmission projects obtain TVA-officer approval. Projects that do not have TVA-officer approval are omitted from the transmission expansion plan until the continued need for the planned corrective action is verified.

## 2.5 Major New and Upgraded Transmission Facilities

This section describes the major new and upgraded transmission facilities included in each Planning Authority's portion of the 2025S and 2025W roll-up integration cases. Major facilities are 230 kV or above. Appendix B of this report includes a complete listing of major new and upgraded projects, as categorized in Section 2.4. Some projects may have multiple facilities listed that are a part of the same project. For example, a long line project may have several line segments and substations between its end points.

### Alcoa Power Generating, Inc.

Alcoa's Yadkin division has no new or upgraded facilities planned.

### Duke Energy Carolinas

DEC included an upgrade of the double-circuit 230 kV lines from McGuire nuclear station to Riverbend switching station and switchable reactors in the double-circuit 230 kV lines between Peach Valley and Riverview switching station. DEC has included two new >200 kV transmission projects in the area of the new 776 MW Lee combined-cycle plant. Several projects in the immediate area of the plant were needed to accommodate the plant's output. Additional 230/100 kV transformer capacity was modeled at Parkwood tie, Oakboro tie, and Cliffside steam station. No other >200 kV projects are expected to be in service by 2025.

### Duke Energy Florida

DEF has included the following 230 kV and 500 kV projects in the 2025 summer and 2025 winter roll-up integration cases:

---

[10] A summary of NEPA is available at [http://www.epa.gov/laws-regulations/summary-national-environmental-policy-act](http://www.epa.gov/laws-regulations/summary-national-environmental-policy-act).

- Williston—new 230/69 kV substation
- Williston to Bronson—new 230 kV line
- Crystal River East—new replacement 230/115 kV substation with second transformer and loop 230 kV lines
- Dona Vista—new 230/69 kV substation
- Disston to 40th Street—new 230 kV line
- Brooksville—new 230/115 kV substation and 230 kV line to Brooksville West

### Duke Energy Progress

DEP has included three new 230 kV transmission projects in the 2025 summer and winter roll-up integration cases. The first is a loop-in of the Richmond–Ft. Bragg Woodruff 230 kV line into the Raeford 230 kV substation that will be placed in service by June 2018. The second is a new 230 kV line from the Jacksonville 230 kV substation to the new Grants Creek 230 kV substation that will be placed in service by June 2020. The third is a new 230 kV line from the new Newport 230 kV substation to the new Harlowe 230 kV substation that will be placed in service by June 2020.

### Electric Energy Inc.

No new Electric Energy, Inc. transmission facilities are included in the 2020 roll-up integration case.

### Florida Power and Light

The projects included in the FPL portion of the roll-up integration case are needed to meet FPL's regulatory requirements for the 10 year planning horizon. FPL has included two new transmission line projects in the 2023 model that will amount to an estimated total of 25 miles of new 230 kV transmission lines.

### Georgia Transmission Corporation

GTC's information is included in the response from Southern Company. Please note that in Appendix B, transmission facilities listed under the PA "SBA" also include GTC transmission projects.

### Independent Electricity System Operator

Ontario is proposing to develop or enhance network transmission facilities to accommodate renewable resources. These transmission enhancements are planned to be in service by 2018. IESO may identify additional transmission development when these resource options have developed further.

The 2025 roll-up integration cases include transmission system reinforcements in various parts of the province such as a new double-circuit 230 kV line between Lakehead and Wawa, the reinforcement of the Oshawa, Whitby and Ajax areas, and the upgrading of the existing double-circuit 230 kV lines between Lambton TS and Longwood TS.

### ISO New England

ISO-NE has included new transmission projects at 230 kV and above in the 2025 roll-up integration cases. Most of these projects are components of either the Maine Power Reliability Project (MPRP) or the New England East–West Solution (NEEWS), two major 345 kV plans anticipated to be in service by 2020 in New England. Other projects include the Vermont Southern Loop 345 kV project, the Long-Term Lower Southeastern Massachusetts (SEMA) project, a new 345 kV substation in Rhode Island, and several additional bulk autotransformers located in all six New England States.

### JEA

The major "state/budget approval" projects included in the roll-up integration cases are needed to meet the generation and transmission performance requirements of the JEA electric system, as forecasted in the 10-year planning horizon. JEA currently is not adding any generator capacity within its service territory but has power purchase agreements with other utilities to meet its future load demand for the 10-year planning horizon. It also has plans to construct a new 230 kV transmission circuit and some additional substations to serve the load.

### LG&E and KU Energy

LG&E and KU have no major (200 kV and above) projects planned at this time.

### MEAG Power

MEAG's information is included in the response from Southern Company. Please note that in Appendix B, transmission facilities listed under the PA "SBA" also include MEAG transmission projects.

### Midcontinent ISO

Table 2-2 shows the planned, major 230 kV and above line additions included in the power-flow models.

**Table 2-2**
**MISO's Planned Major Line Additions, 230 kV and Above, Included in the Power-Flow Models**

| Project Description | Location | Mileage | Expected In-Service Date |
|---|---|---|---|
| Turkey Hill–Cahokia Rebuild to 345 kV | IL | 19 | 06/01/2015 |
| Lutesville–NW Cape 345 kV | MO | 11 | 06/01/2016 |
| SE Twin Cities–Rochester, MN–LaCrosse, WI 345 kV | MN/WI | 118 | 09/30/2016 |
| Sidney–Rising 345 kV Multi-Value Project (MVP) | IL | 25 | 11/15/2016 |
| Big Stone South–Brookings 345 kV MVP | SD | 69 | 09/30/2017 |
| Palmyra Tap – Quincy - Meredosia–Ipava and Meredosia–Pawnee 345 kV MVP | IL/MO | 186 | 11/15/2017 |
| Reynolds–Greentown 765 kV MVP | IN | 69 | 06/01/2018 |
| Lakefield Jct.–Winnebago–Winco–Kossuth County and Obrien County–Kossuth County–Webster 345 kV MVP | IA/MN | 218 | 06/01/2018 |
| Pana–Mt. Zion–Kansas–Sugar Creek 345 kV MVP | IL/IN | 141 | 11/15/2018 |
| Zachary–Ottumwa 345 kV MVP | IA/MO | 73 | 11/15/2018 |
| Fargo–Sandburg–Oak Grove 345 kV MVP | IA/IL | 71 | 11/15/2018 |
| Pawnee–Pana 345 kV MVP | IL | 34 | 11/15/2018 |
| Zachary–Maywood 345 kV MVP | MO | 60 | 11/15/2018 |
| Richardson–Iberville 230 kV | LA | 11 | 12/01/2018 |
| Winco–Hazleton 345 kV MVP | IA | 206 | 12/31/2018 |
| Green Bay–Morgan 345 kV | WI | 40 | 05/31/2019 |
| Ellendale–Big Stone South 345 kV MVP | ND/SD | 165 | 12/31/2019 |
| Reynolds–Burr Oak–Hiple 345 kV MVP | IN | 97 | 12/31/2019 |
| Dorsey–Iron Range 500 kV | MN/ Manitoba | 382 | 06/01/2020 |
| N LaCrosse–N Madison–Cardinal–Eden–Hickory Creek 345 kV MVP | IA/MN/WI | 291 | 12/31/2020 |

Table 2-3 shows the transmission projects included in the model as "proposed" projects, which are currently being evaluated for recommendation in 2015 to the MISO Board of Directors for approval.

**Table 2-3**
**Proposed MISO Transmission Projects Included in the Power-Flow Models**

| Project Description | Location | Mileage | Expected In-Service Date | Expected Regional Approval Date |
|---|---|---|---|---|
| Morgan Valley–Beverly 345 kV | IA | 7 | 12/31/2017 | 2015 |
| Schriever–Bayou Vista 230 kV | LA | 30 | 06/01/2018 | 2015 |
| Sulphur Lane–Carlyss 500 kV | LA | 11 | 06/01/2018 | 2015 |
| Carlyss–Solac 230 kV | LA | 12 | 06/01/2018 | 2015 |
| China–Stowell 230 kV | TX | 20 | 12/01/2018 | 2015 |
| Duff–Rockport–Coleman 345 kV | IN | 29 | 01/01/2021 | 2015 |
| Lewis Creek–NSUB2 230 kV | TX | 40 | 01/01/2021 | 2015 |

### New York ISO

NYISO has included the following projects in both the 2025 summer and winter roll-up integration cases:

- Transmission owners' transmission solutions (TOTS)
- CPV Valley combined-cycle unit (656 MW nameplate), in service
- Huntley generator, in service

### PJM Interconnection

The 230 kV and above line upgrades are provided Appendix B of this report. To keep the list manageable, it excludes many high-voltage projects that strictly involve breaker replacement or bus work that does not affect lines, or upgrades to transformers to lower voltages. A subset of the upgrades reported in the appendix was selected to depict a sampling of the more significant upgrades being implemented through PJM's RTEP process.[11] Table 2-4 describes these lines.

**Table 2-4**
**Sample of Projects Depicting the More Significant Upgrades Being Implemented through the PJM RTEP**

| Project | Date Required for Reliability | Status |
|---|---|---|
| Loop the Meadow Lake–Olive 345 kV circuit into the Reynolds 765/345 kV station | 6/1/2018 | Board approved; engineering procurement |
| Upgrade the Chalk Point - T133TAP 230 kV Ckt. 1 (23063) and Ckt. 2 (23065) to 1200 MVA ACCR | 6/1/2018 | Board approved; engineering procurement |
| Build a second Loudoun–Brambleton 500 kV line within the existing ROW | 6/1/2018 | Board approved; engineering procurement |
| Rebuild Susquehanna–Jenkins 230 kV circuit | 11/30/2019 | Board approved; engineering procurement |
| Rebuild the Siegfried–Frackville 230 kV line | 6/1/2018 | Board approved; engineering procurement |
| Reconfigure the Sewaren 230 kV, convert the two 138 kV circuits from Sewaren–Metuchen to 230 kV circuits including Lafayette and Woodbridge substation; reconfigure the Metuchen 230 kV station to accommodate the two converted circuits | 6/1/2015 | Board approved; engineering procurement |
| Build a new 230 kV line from Dooms to Lexington on existing ROW | 6/1/2016 | Board approved; engineering procurement |

[11] A complete list of all approved RTEP upgrades, as well as a brief description of the facility, upgrade driver, and current status is available at PJM's "Transmission Construction Status" webpage: http://www.pjm.com/planning/rtep-upgrades-status/construct-status.aspx.

| Project | Date Required for Reliability | Status |
|---|---|---|
| Reconductor the AEP portion of the Cloverdale–Lexington 500 kV line | 3/1/2014 | Board approved; engineering procurement |
| Construct 230 kV OH line along existing line #2035 corridor, approx. 2.4 miles from Idylwood–Dulles Toll Road (DTR) and 2.1 miles on new ROW along DTR to new Scott's Run substation | 6/1/2017 | Board approved; engineering procurement |
| Construct a new Byron to Wayne 345 kV circuit | 6/1/2017 | Required for economics |
| PSEG 345 kV double-circuit solution—Isolate Hudson 230 kV from the 138 kV at Marion and 345 kV at Farragut; 138 kV facilities on the path from Linden to Bergen to double circuit 345 kV | 6/1/2015 | Planned; not yet board approved |
| Convert the Wreck and rebuild existing Remington CT–Warrrenton 230 kV (approx. 12 miles) as a double-circuit 230 kV line | 6/1/2017 | Board approved; engineering procurement |
| Construct a new 230 kV line approximately 6 miles from NOVEC's Wheeler Substation to new 230 kV switching station in Vint Hill area | 6/1/2017 | Board approved; engineering procurement |
| Convert NOVEC's Gainesville–Wheeler line (approximately 6 miles) to 230 kV | 6/1/2017 | Board approved; engineering Procurement |
| Rebuild Buggs Island–Plywood 115 kV Line #127 (25.8 miles) to current standards with summer emergency rating of 353 MVA at 115 kV. The line should be rebuilt for 230 kV and operated at 115 kV. | 12/31/2021 | Board approved; engineering procurement |
| Build a 230 kV line from Remington substation to Gordonsville substation utilizing existing ROW | 6/1/2018 | Board approved; engineering procurement |
| Reconductor two spans of the Graceton–Safe Harbor 230 kV transmission line. Includes termination point upgrades | 6/1/2019 | Board approved; engineering procurement |
| Reconductor three spans limiting Brunner Island–Yorkana 230 kV line, add two breakers to Brunner Island switchyard, upgrade associated terminal equipment | 6/1/2019 | Board approved; engineering procurement |

### PowerSouth Energy Cooperative

PowerSouth has no major (200 kV and above) projects planned at this time.

### Santee Cooper

Santee Cooper’s major transmission projects for 2025 include the continued development of a 230 kV transmission system needed for delivering generator output to the load and maintaining reliability of the transmission system. Table 2-5 shows the major transmission improvements included in the 2025 roll-up integration cases.

**Table 2-5**
**Major Santee Cooper Transmission Improvements Included in the 2025 Roll-Up Integration Cases**

| Projects | Scheduled Completion Year |
|---|---|
| Richburg—Flat Creek 230 kV line | 2016 |
| Sandy Run 230-115 kV substation | 2018 |
| Winyah—Bucksville 230 kV line | 2018 |
| Marion—Red Bluff 230 kV line | 2018 |
| Pomaria—Sandy Run 230 kV line | 2018 |
| Sandy Run—Orangeburg 230 kV line | 2019 |
| Dalzell—Lake City 230 kV line (per budget) | 2020 |
| Pinewood 230-115 kV substation | 2021 |
| Sandy Run—Pinewood 230 kV line | 2021 |

### South Carolina Electric and Gas

The SCE&G transmission system did not include any major transmission improvements in the 2025 roll-up integration cases.

### Southern Company

**Error! Reference source not found.** shows the major upgrades within the Southern Balancing Authority Area included in the 2025 roll-up integration cases.

**Table 2-6**
**Major Transmission Improvements in the Southern Balancing Authority Area Included in the 2025 Roll-Up Integration Cases**

| Project | Scheduled Completion |
|---|---|
| Upgrade Barry–Crist 230 kV line | Summer 2017 |
| Reconductor Gorgas–Jasper tap 161 kV line | Summer 2017 |
| Construct Thomson Primary–Vogtle 500 kV line | Summer 2017 |
| Wadley 500/230 kV Project | Summer 2017 |
| Construct Holt–South Bessemer 230 kV line | Summer 2019 |
| Construct Belleville–North Brewton 230 kV line | Summer 2020 |
| Sharon Springs 230/115 kV Project | Summer 2020 |

## Southwest Power Pool

The major transmission improvements to the SPP transmission system included in the 2025 roll-up integration cases are listed in Table 2-7. To keep the list manageable, it excludes many high voltage projects that strictly involve breaker replacement or bus work that does not affect lines or upgrades to transformers to lower voltages.

**Table 2-7**
**Major Transmission Improvements to the SPP Transmission System**
**Included in the 2025 Roll-Up Integration Cases**

| Project | Mileage | Scheduled Completion Year |
|---|---|---|
| Iatan–Nashua 345 kV | 31 | 2015 |
| Potash Junction–Road Runner 345 kV (op @ 230 kV) | 40 | 2015 |
| Valiant–NW Texarkana 345 kV | 76 | 2016 |
| Messick 500/230 kV transformer | | 2016 |
| Hoskins–Neligh 345 kV | 41 | 2016 |
| Nebraska City–Mullins Creek–Sibley 345 kV | 215 | 2016 |
| Carlisle–Wolfforth 230 kV | 17 | 2017 |
| Chisholm–Gracemont 345 kV | 104 | 2018 |
| Elm Creek–Summit 345 kV | 58 | 2018 |
| Gentleman–Cherry Co–Holt Co 345 kV | 227 | 2018 |
| Kiowa–North Loving–China Draw 345 kV | 39 | 2018 |
| Hobbs–Kiowa 345 kV | 47 | 2018 |
| Arcadia–Redbud 345 kV | 5 | 2019 |
| Tuco–Yoakum–Hobbs 345 kV | 159 | 2020 |
| Cimarron–Matthewson–Tatonga–Woodward 345 kV (circuit 2) | 126 | 2021 |

## Tennessee Valley Authority

The major upgrades to the TVA transmission system included in the 2025 roll-up integration cases include the following:

- Long-range load-flow studies show that a high-voltage source will be required in the Cookeville area when the area loads reach 650 to 700 MW. This new 500 kV source will be needed to supply the increasing area load and to transfer the increased generation from the 500 kV system to the 161 kV system. The Plateau 500/161 kV transformer will be in service by December 2018.
- Long-range load-flow studies show that while Widows Creek unit 8 is off line during shoulder peak scenarios with Raccoon Mountain pumping, the Raccoon Mountain 500/161 kV transformer can overload. The second Widows Creek 500/161 kV transformer will be in service by December 2019.
- The lower Mississippi area is currently supported by three long 161 kV transmission lines out of West Point. Long-range load-flow studies show that low voltages and overloads

appear when two lines are out during a maintenance case study (N-1-1). Other issues also exist when two lines are out in a peak case study (N-2). Two lines have been out at the same time due to a tornado storm. This new line, Red Hills–Leake 161 kV, will correct N-1-1 and N-2 low voltages and overloads. The expected in-service date is June 2019.

- Long-range load-flow studies show that while Colbert Fossil units 15 are off line, the Union–Tupelo 161 kV #1 or #2 line can overload. The new Union–Tupelo 161 kV #3 line will be in service by June 2016.
- Long-range load-flow studies have determined that several 161 kV overloads are present in the Nashville area. The addition of a second 500/161 kV transformer at Pin Hook, new line construction, and line upgrades would correct the thermal violations that could occur during contingency events in the Nashville area. The second Pin Hook 500/161 kV transformer will be in service by December 2018.

## 2.6 Generation Assumptions (Additions and Retirements)

This section describes assumptions associated with the modeling of new and retiring generation facilities. As with transmission facilities, the processes for including new generation and generation retirements vary among the different planning authorities. This section describes, in general terms, the processes followed and the assumptions made in the 2025 cases regarding generation additions and retirements.

Appendix C provides a complete, detailed listing of all new and upgraded generation projects included in the 2025 roll-up integration cases. The “Projected In-Service Date” column indicates whether the facility was included in the 2025S and 2025W models (“2025S”) or just the 2025W model (“2025W”). Planning authorities have agreed to the following terms to describe the status of future generation projects:

- **Construction**—resource is under construction or is being commissioned
- **Committed**—resource has completed the interconnection request process or has obtained applicable transmission service
- **Proposed**—resource has been proposed and included in the planning process but does not have applicable transmission service

Renewable Portfolio Standards vary from state to state and are expressed in terms of percentage of energy that must be produced from renewable resources for a given state or entity. The entities responsible for meeting the RPS requirements are typically load-serving entities, not the planning authorities.

The transmission analysis performed in this study involves analyzing system reliability during summer peak periods to assess potential transmission system constraints. The renewable resources provided to each Planning Authority by its LSEs and other market participants for transmission planning purposes are included in the power-flow modeling of the study. Appendix C lists new generation additions by fuel type, including all new renewable resources included in the modeling. Capacity values for each renewable resource and its output modeled in the peak power-flow cases are also included in Appendix C.

### Alcoa Power Generating, Inc.

Alcoa's Yadkin division has no generation changes planned.

### Duke Energy Carolinas

The cases include DEC and IPP generation facilities presently in operation. Duke has repowered Lee 3 from coal to gas operation and will add a 776 MW combined-cycle plant at the Lee site. Projected 1,389 MW of additional IPP generation has been modeled.

### Duke Energy Florida

DEF announced that it would retire its Crystal River coal units 1 and 2 after the second unit at the Levy County site completed its first fuel cycle. At present, the Levy County project has been canceled, and the retirements of Crystal River coal units 1 and 2, Higgins combustion turbines (CTs), and Suwannee CTs have all been deferred until further notice.

### Duke Energy Progress

DEP has no generation additions or retirements in the 2025 summer and winter roll-up integration cases.

### Electric Energy Inc.

Electric Energy, Inc. has no generation additions or retirements in the 2020 roll-up integration case.

### Florida Power and Light

Future projects that have undergone FPL's internal budget review process as well, as those projects that are representative of the *Ten-Year Site Plan* filing with the Florida Public Service Commission, are included in the roll-up integration cases. Approximately 2,500 MW of additional generation (compared with 2012) is included in the FPL 2025 case. All these projects have gone through the FPL System Impact Study process and are part of FPL's official resource plan. Florida Power and Light plans to retire the Turkey Point #1 steam turbine (396 MW) in 2016. The generator will be converted to synchronous condenser operation. FPL's TYSP filing serves as an input for the generation and load assumptions for modeling purposes.

### Georgia Transmission Corporation

GTC's member cooperatives provide generation resource assumptions to GTC. In Appendix C, generation resources listed under the PA "SBA" also include generation resources identified by GTC's member cooperatives.

### Independent Electricity System Operator

Ontario plans to retire six units at Pickering A and B nuclear generation stations by the end of 2020, which will remove approximately 3,240 MW of generation from service. In response to the retirement of these units, Clarington TS was built to reinforce the supply of Oshawa–Whitby areas, and approximately 6,000 MW of renewable generation resources, including wind, solar, biomass, and hydro, are planned to come on line and connect to the Ontario grid. Most of these resource additions are anticipated to be on line by the end of 2018, with further development still under planning assessments. Table 2-8 shows the expected retirement dates for the Pickering units.

**Table 2-8**
**Expected Retirement Dates for Pickering Units in IESO**

| Unit | System | Expected Retirement Date |
|---|---|---|
| Pickering G1 | Ontario | 2020 |
| Pickering G4 | Ontario | 2020 |
| Pickering G5 | Ontario | 2020 |
| Pickering G6 | Ontario | 2020 |
| Pickering G7 | Ontario | 2020 |
| Pickering G8 | Ontario | 2020 |

### ISO New England

ISO-NE has included several new generation projects in the roll-up integration cases. These projects have been approved under Section I.3.9 of the ISO New England tariff. Projects over 100 MW include uprates to a number of hydroelectric and steam turbine plants, as well as eight new wind farms, two natural gas combined-cycle plants, and gas combustion-turbine projects. ISO-NE generally does not assume generation retirements unless a generator has taken formal action to withdraw from the Forward Capacity Market by submitting either a "non-price" retirement bid or a delist bid.

### JEA

JEA is jurisdictional in the State of Florida and subject to Florida's *Electrical Power Plant Siting Act* and *Transmission Line Siting Act*. The Florida Department of Environmental Protection administers these acts, and under the statutes of these acts, the governor and cabinet sit as the siting board and review applications for power plant and transmission line certifications that reach certain minimum levels of impact. Not all power plants and transmission line constructions require cabinet approval. The statutes for these acts require the Florida Public Service Commission to review and grant the "Certificate of Public Convenience and Necessity" applications.

JEA annually produces a *Ten-Year Site Plan* filing to the Florida Public Service Commission, which contains the 10-year forecast of demand and the associated resources required to meet JEA's 15% planning reserve target. The TYSP serves as the official source for the generation resources provided for in the FRCC load-flow model. JEA currently does not have any plans to retire any existing generators in the 10-year planning horizon.

### LG&E and KU Energy

The respective LG&E and KU load-serving entities (and market participants securing point-to-point transmission service) provided the resource assumptions contained within the 2025 roll-up integration cases. Resources without long-term firm transmission service may be included in the model but at zero output. "Committed" resources include designated network resources and other resources that have secured long-term firm transmission service. "Proposed" resources are those the LSEs provided to meet their forecasted load-service requirements for future years but have not been designated as a network resource pursuant to the LG&E/KU OATT.

### MEAG Power

MEAG member participants provide the generation resource assumptions. In Appendix C, generation resources listed under the PA "SBA" also include generation resources identified by MEAG.

### Midcontinent ISO

Within MISO, the future generation resources modeled come from the MISO generation interconnection process and resource forecasts based on public policy requirements. Future generators with signed interconnection agreements are included in models.

### New York ISO

The NYISO has included new generation projects in its 2025 roll-up integration cases. Projects that have passed certain milestones are included in the NYISO planning databases used in its Comprehensive System Reliability Planning Process. CPV Valley (656 MW nameplate) has been added to the cases after the developer of the generation facility announced that construction has commenced.

### PJM Interconnection

Section 2.4 describes additional information on the PJM planning process. The transmission system is planned for the forecasted load growth and interconnection requests that have reached a specified degree of commitment. This process is according to PJM's tariff, agreements, and business rules approved in the regulatory and stakeholder processes. In this capacity, PJM's business is only involved with generation when they initiate a request for interconnection to the transmission system.

In addition to existing in-service generation, the 2020 and 2025 roll-up integration cases incorporate generation with signed Interconnection Service Agreements, generation with signed Facility Study Agreements (FSAs), and announced generation deactivations (e.g., retirements). Since load-serving entities are responsible for state Renewable Portfolio Standards, PJM plans for the LSE's resources as they enter the generation queue and fulfill their interconnection commitments. Section 2.4 of this report also describes PJM's public policy transmission planning. The new generation in PJM with signed Interconnection Service Agreements and the generation in PJM with signed Facility Study Agreements, are as follows:

- Mid-Atlantic PJM included 8,737 MW of new generation with signed ISAs and 5,267 MW of projects with signed facility study agreements.
- Western PJM included 6,374 MW of new generation with signed ISAs and 10,519 MW of projects with signed facility study agreements.
- Southern PJM included 2,449 MW of new generation with signed ISAs and 300 MW of projects with signed facility study agreements.

PJM's power-flow case transmission model includes the network upgrades necessary to accommodate the interconnection and operation of new generation for which an ISA has been signed as well as generation with a signed FSA.[12] Appendix C of this report provides a list of these projects. Announced unit retirements that PJM has accepted are deactivated in the roll-up power flow.[13]

The PJM RTEP process projects renewable requirements based on a detailed review of the state statutes and other information on a state by state basis. PJM includes existing installed renewables and queued generation with signed Interconnection Service Agreements or Facilities Agreements into its baseline RTEP planning and market efficiency planning. This will result in planned transmission upgrades to maintain system capability for delivering these renewables in the PJM market. PJM is responsible for ensuring the deliverability of generation committed to PJM load according to the applicable tariffs and agreements. This is achieved through PJM's comprehensive RTEP planning process.

### PowerSouth Energy Cooperative

Resource assumptions contained within the 2025 roll-up integration cases for PowerSouth were determined through power supply studies and our annual capacity planning process. PowerSouth has no "Committed" resources between 2015 and 2025. One "Proposed" resource needed to meet our forecasted load growth before 2025. Resource additions in PowerSouth's generation expansion plan are not subject to approval by state regulatory agencies, but do require approval by RUS. PowerSouth and its members are not currently impacted by any state or federal Renewable Portfolio Standards. No generation retirements are planned between 2015 and 2025.

### Santee Cooper

For the 2025 roll-up integration cases, the generation assumptions include both existing generation and future generation as specified in Santee Cooper's current Generation Expansion Plan. The current Generation Expansion Plan, updated yearly, has Santee Cooper in partial ownership with SCE&G in two nuclear units budgeted and scheduled for commercial operation in 2019 and 2020. The existing generation expansion plan also includes approximately 470 MW of retired generation.

### South Carolina Electric and Gas

Resource additions included in the 2025 roll-up integration cases for SCE&G include committed generation projects under construction. SCE&G is scheduled to complete construction on VC Summer Nuclear units 2 & 3 in 2018 and 2019 and will share joint ownership of these units with Santee Cooper. The Public Service Commission of South Carolina has approved these projects.

---

[12] A listing of all generation and merchant transmission interconnection requests in PJM's queues is available at the following PJM website links: Generation, http://www.pjm.com/planning/generation-interconnection.aspx; Merchant Transmission, http://www.pjm.com/planning/merchant-transmission.aspx.

[13] A list of these units and scheduled deactivation dates is available at the PJM website: http://www.pjm.com/planning/generation-deactivation.aspx.

LSEs within the SCE&G planning area have announced planned retirements in specific years within the next 10 years. A potential generator retirement option is modeled in the roll-up integration cases where the outputs of these potential retirement units are set at zero MW.

### Southern Company

The respective LSEs (and market participants through securing point-to-point transmission service) provided the resource assumptions contained within the 2025 roll-up integration cases for the Southern Companies. Resources that have been announced for retirement have been removed from the cases. Resources without long-term firm transmission service may be included in the cases, but at zero output. "Committed" resources include designated network resources and other resources that have secured long-term firm transmission service. "Proposed" resources are those the LSEs provided to meet their forecasted load service requirements in future years but have not been designated as a network resource pursuant to the OATT.

### Southwest Power Pool

SPP includes new generators that have a FERC-filed Interconnection Agreement (IA). New generators without an IA are not added to the models until the IA is executed. Proposed generators without an IA may be added as needed to address generation deficiencies. SPP projects 4,264 MW of generation retirements between 2015 and 2025, not including retirements or derates that may occur in response to developing EPA regulations.

### Tennessee Valley Authority

Resource assumptions contained within the 2025 roll-up integration cases for TVA are included in TVA's official capacity expansion plan and provided by TVA's System Planning group (and market participants through securing PTP transmission service). "Committed" resources include designated network resources and other resources that have secured long-term firm transmission service. "Proposed" resources are those included in TVA's official capacity expansion plan to meet forecasted load service requirements in future years but have not been designated as a network resource pursuant to the OATT. The resource assumptions for TVA are as follows:

- Watts Bar Nuclear unit 2 is scheduled for operation in 2016.
- Johnsonville Fossil units 1 through 4 will cease generation by December 2017 as part of a consent decree with the US Environmental Protection Agency. Units 5 through 10 were idled in 2012.
- Colbert Fossil units 1 through 4 will be retired in April 2016. Unit 5 was idled in 2013.
- Paradise Fossil units 1 and 2 will be idled by the end of 2017. Unit 3 will continue operation. TVA is investing to build a gas-fired plant that will replace Paradise units 1 and 2. The new plant will be a "3 x 1" (i.e., three gas units and one steam unit) combined-cycle facility with 1,100 MW of power capacity.

## 2.7 Generation Dispatch Description

This section explains the methods each Planning Authority used to dispatch the available generation in the 2025S and 2025W roll-up integration cases. All PAs apply methods of dispatching their systems representative of actual system dispatch expected to occur based on economic and physical considerations. The precise base dispatch is not critical to determining transmission-expansion plans because these plans are developed on the basis of testing the systems against a variety of system configurations, including variations from the base dispatch, to ensure reliable system performance consistent with applicable system performance standards.

### Alcoa Power Generating, Inc.

Alcoa's Yadkin division load is served from the Badin generator.

### Duke Energy Carolinas

The DEC system generation dispatch is modeled on the basis of economic dispatch in accordance with the priorities identified in the LSEs' resource projections and according to executed contracts for the sale of firm energy.

### Duke Energy Florida

The DEF system generation dispatch is modeled on the basis of economic dispatch in agreement with the priorities identified in the LSEs' resource projections and according to executed contracts for the sale of firm energy.

### Duke Energy Progress

The DEP system generation dispatch is modeled on the basis of economic dispatch in agreement with the priorities identified in the LSEs' resource projections and according to executed contracts for the sale of firm energy.

### Electric Energy Inc.

Electric Energy, Inc. resources are fully dispatched in the 2020 roll-up integration cases.

### Entergy Services

To meet the area requirements, the model dispatches firm generation, followed by non-firm network resources, generation owned by the LSEs, and then non-firm energy-only resources. Entergy dispatches generation representing firm energy contracts and economically dispatches firm network resources for load. The dispatch of additional generation is pro-rata in the following order: non-firm network resources; LSE-owned non-firm energy-only generation; then non-firm, energy-only resources within the BA owned by others.

### Florida Power and Light

The dispatch of FPL's generation resources is based on economic order for meeting FPL's forecasted load and firm contractual requirements.

### Georgia Transmission Corporation

The dispatch of the generation resources contained within the roll-up integration cases is based upon the dispatch merit order identified in the LSEs' resource projections (including GTC's member cooperatives). In addition, generating units associated with long-term firm transmission commitments to external areas are dispatched "on" at an output level consistent with the interchange values discussed in Section 2.3.

### Independent Electricity System Operator

The modeling of IESO system generation dispatch is based on economic dispatch in accordance with the demand to be served and the resource projections for the scenario under study.

### ISO New England

In real-time operations, ISO-NE uses security-constrained dispatch of generation through a competitive wholesale market that results in the operation of the lowest-priced resources to meet system demand for electricity, while avoiding unacceptable potential post-contingency system conditions., The generation dispatch in the Units typically among the least expensive (for example, nuclear, coal, and natural gas combined cycle) are dispatched, and units that typically have higher costs and bids (for example, oil combustion turbines and fast-start units) are left off line. The output of wind and hydroelectric generation is modeled consistent with historical generation data for these units at summer peak load conditions. The New England regional system planning process examines many different possible resource dispatch and unavailability conditions.

### JEA

All JEA generators in the roll-up integration cases are dispatched first on minimum contractual requirements and then on an economic basis.

### LG&E and KU Energy

The LG&E and KU system generation dispatch is modeled on the basis of economic dispatch in accordance with the priorities identified in the resource projections each LSE provided.

### MEAG Power

The dispatch of the generation resources contained within the roll-up integration cases to serve MEAG participant load is based on the dispatch merit order identified in the resource projections. MEAG Power is not currently subject to RPS mandates.

### Midcontinent ISO

The dispatch of MISO members' generation is market-wide using the Security-Constrained Economic Dispatch (SCED) methodology. Renewable generation is set to its desired level before applying the SCED, and renewable resources are not adjusted in the SCED process. Wind generators are dispatched at 14.7% of nameplate during summer peak conditions and 30% for winter peak conditions. New and retiring generation is incorporated through the normal MTEP model building process.

### New York ISO

The NYCA system generation dispatch includes only the impact of firm external transactions. Generation dispatch is consistent with typical dispatch observed during peak load.

### PJM Interconnection

Internal to PJM, the roll-up model dispatch is based on a representative market-based dispatch prepared by the planning department. Similar to the load representation in this model, the dispatch represents only a single snapshot of a representative dispatch as a starting point reference model. The annual series of PJM planning analyses examines thousands of alternative dispatch scenarios. Because of this and because PJM operates and is planned as a single system, these snapshot PJM dispatch values change moment to moment based on a single-area market. The starting representative market dispatch therefore is not a focus for PJM planning analyses.

### PowerSouth Energy Cooperative

The generation dispatch of the resources contained within the 2025 roll-up integration cases are economically dispatched according to current fuel-cost assumptions and availability.

### Santee Cooper

The Santee Cooper generation dispatch used in the 2025 roll-up integration cases is a strictly economic dispatch model. Nuclear units and large coal base-load units are all dispatched first, and then all other generating units are economically dispatched according to cost. No units are dispatched out of merit to alleviate system loading constraints.

### South Carolina Electric and Gas

The dispatch of generation resources within the SCE&G planning area is based on the economic merit order of the generating units and is set to meet the requirements of LSEs and executed contracts for the sale of firm energy with firm transmission service.

### Southern Company

The generation dispatch of the resources contained within the 2025 roll-up integration cases is based on the dispatch merit order identified in the LSE resource projections. In addition, long-term firm transmission commitments to external areas are dispatched “on” at an output level consistent with the interchange values discussed in Section 2.3.

### Southwest Power Pool

Each SPP member dispatches its generation in the model to cover its own projected load obligations, including any approved long-term, firm service transactions.

### Tennessee Valley Authority

Market participants within TVA’s Balancing Authority are dispatched at the level of their confirmed long-term, firm transmission service. Production cost dictates the order in which TVA’s generation fleet is dispatched in the 2025 roll-up integration cases. TVA does not apply a security-constrained dispatch to alleviate system constraints. The typical order of dispatch from most economic to least economic by generator technology is as follows:

- Hydro
- Nuclear

- Pumped storage
- Fossil
- Combustion-cycle gas
- Combustion turbine gas

In addition, long-term, firm transmission commitments to external areas are dispatched "on" at an output level consistent with the interchange values discussed in Section 2.3.

# Section 3
# Interregional Transmission (Gap) Analysis

Power-flow analysis is often focused on forecasted summer and winter peak conditions, which typically (but not always) represent highest loadings on the facilities. To perform interconnection-wide power-flow analysis, in addition to the modeling developed by each Planning Authority, an underlying exchange of energy or interchange among balancing authority areas (BAAs) must be established. It is common for transmission providers to have long-term, firm transmission service commitments with market participants involving deliveries to other balancing authority areas without the market participants "matching" these transmission service commitments with the associated transmission providers in the receiving balancing authority areas. Because market participants can and do purchase long-term firm transmission service on a so-called partial-path basis, determining the energy exchange or interchange among BAAs requires coordination.

EIPC's Interregional Transmission Analysis for the 2025 planning year is a power-flow analysis based on the 2025 roll-up models. These models represent power system facilities and loads for the summer and the winter peak forecast for 2025, as developed by each Planning Authority during their then-current planning cycle. The interchange used for this analysis was developed through a coordinated effort of the EIPC planning authorities and is based on a subset of transmission service commitments representing full-path transactions from source to sink.

A contingency analysis was performed in a collective manner, as described in Sections V.C. and V.D. of the *Steady-State Modeling Load-Flow Working Group Procedural Manual*. The objective of this analysis is to identify potential interconnection-wide power-flow interactions that may result from the effects of one PA's plans on another. Because this particular set of power flows and energy exchange (interchange) may differ from those assessed during local and regional planning activities, additional constraints may be identified, particularly where interchange or generation dispatch patterns in other regions may differ from local commitments and assessments. To the extent additional constraints or "gaps" are identified during the interregional analysis, the PAs' respective regional planning processes will refer to these constraints and the accompanying power-flow conditions.

This task is a screening analysis, and the PAs' regional planning processes will refer to its results (potential gaps) for detailed assessments. Detailed analysis may or may not indicate a need for system upgrades in future planning cycles. Items identified in the "gap" analysis should not be construed as the baseline topology of the 2025 roll-up modeling needing modifications to be applied in subsequent scenario analysis.

## 3.1 Thermal and Voltage Criteria

System performance was assessed in a manner consistent with the NERC TPL (transmission planning) Reliability Standards, as described in the *Steady-State Modeling Load-Flow Working Group Procedure Manual*, Section V.D. Bulk electric system elements above 100 kV were monitored. Thermal and voltage criteria applicable to each facility were applied.

## 3.2 Contingency Selection

As described in the *Steady-State Modeling Load-Flow Working Group Procedure Manual*, Section V.C., contingencies representing outages of all transmission elements 230 kV and above and all transformers with a low-side voltage rating of 110 kV or above were modeled and revised. Planning authorities were also given discretion to simulate contingencies of transmission elements below 230 kV, depending on the composition and characteristics of each PA's bulk electric system.

## 3.3 Interregional Analysis Results

In this section, each Planning Authority provides a list of the constraining facilities identified as a result of the collective or individual PA analysis. The constraints identified were assumed to result from neighboring system interactions that have yet to be assessed in detail. In some cases, the cause and system interactions associated with a potential reliability issue may be difficult to pinpoint. Issues identified will inform the future planning cycles of the PAs' regional planning processes (see Section 4).

### 3.3.1 Summary of Thermal Results

A collective thermal analysis was performed on the 2025 summer and winter peak roll-up cases for each Planning Authority system (NPCC, MISO, PJM, SERC, SPP, and FRCC). Several thermal facility issues that meet the reporting requirements of Section 3.1 were identified in each area for both the summer and winter peak cases and summarized in the tables below (Table 3-1 to Table 3-24). The highest percentage overload was listed for branches found to be overloaded for multiple contingencies.

The respective concerned planning authorities provided the mitigation plans for the identified issues. For the regions with the mitigation plans and upgrades, the thermal analysis results from both the pre-upgrade and post-upgrade systems are presented. The mitigation actions for the thermal issues identified are also reported in the tables. For most of the thermal constraints identified in the NPCC area, the mitigation plans are either operator actions or Special Protection Systems (SPSs).

## Independent System Operator New England

**Table 3-1**
**Thermal Overloads in the ISO-NE Area, Summer 2025 Case**

| Monitored Element | Normal or LTE Rating (MVA) | Loading % | Contingency |
|---|---|---|---|
| 100113 Wyman Hydro 115.00 100172 Bigelow 115.00 1 | 164 | 102.1 | Base case |
| 103029 Powersville 115.00 103118 Powersville 34.500 1 | 50 | 104.2 | Loss of 100002 [Orrington 345] - 190237 [Br3016 345.0] Ckt 1 |
| 104127 Seabrook 345.00 104128 Nu_394_Sbk 345.0 1 | 1,793 | 110.4 | Loss of 104143 [Scobie Pond 345.00] - 104151 [Lawrence Rd 345.00] Ckt 1 |
| 110759 Mystic Ma 345.00 110766 Kingston St 345.00 1 | 650 | 101.4 | Loss of 110759 [Mystic Ma 345.00] - 110766 [Kingston St 345.00] Ckt 2 |
| 110759 Mystic Ma 345.00 110766 Kingston St 345.00 2 | 650 | 101.4 | Loss of 110759 [Mystic Ma 345.00] - 110766 [Kingston St 345.00] Ckt 1 |
| 110816 Somervil 510115.00 110818 Mystic Ma 115.00 1 | 109 | 117.4 | Base case |
| 110817 Somervil 511115.00 110818 Mystic Ma 115.0 1 | 109 | 119.3 | Base case |
| 113975 King St_54 115.00 113977 King St 54_T115.0 1 | 289 | 112.5 | Loss of 113952 [Ward Hill 345.00] - 114063 [W Amesbury 345.00] Ckt 1 |
| 113975 King St_54 115.00 114075 W Amesbury 115.0 1 | 289 | 156.9 | Loss of 113952 [Ward Hill 345.00] - 114063 [W Amesbury 345.00] Ckt 1 |
| 116009 Northfld Mt 345.00 116011 Northfld-12 345.00 1 | 608 | 102.7 | Loss of 116013 [Northfld-34 345.00] - 116014 [Northfield3x99.000] Ckt 3 |
| 116011 Northfld-12 345.00 116012 Northfield1x99.000 1 | 508 | 118.0 | Base case |

**Table 3-2**
**Thermal Overloads in the ISO-NE Area, Winter 2025 Case**

| Monitored Element | Normal or LTE Rating (MVA) | Loading % | Contingency |
|---|---|---|---|
| 116011 Northfld-12 345.00 116012 Northfield1x99.000 1 | 584 | 119.9 | Loss of 116009 [Northfld Mt 345.00] - 116013 [Northfld-34 345.00] Ckt 1 |
| 103029 Powersville 115.00 103118 Powersville 34.500 1 | 50 | 100.2 | Base case |
| 110816 Somervil 510115.00 110818 Mystic Ma 115.0 1 | 109 | 100.1 | Base case |
| 110817 Somervil 511115.00 110818 Mystic Ma 115.0 1 | 109 | 109.5 | Base case |

## Independent System Operator New York

**Table 3-3**
**Pre Upgrades—Thermal Overloads in the NYISO Area, Summer 2025 Case**

| Monitored Element | Normal or LTE Rating (MVA) | Loading % | Contingency |
|---|---|---|---|
| 125040 N.Cat. 1 115.00 137507 Boc 2t 115.00 2 | 120 | 103.1 | D557:Sb:Hurl345 |
| 126274 E13st 47 345.00 147829 Astor345 345.0 1 | 621 | 100.3 | Loss of 126275 [E13st 48 345] - 147829 [Astor345 345] Ckt 1 |
| 126283 Gothls N 345.00 126286 Gowanusn 345 1 | 845 | 130.8 | Loss of 126285 [Gothls S 345] - 126287 [Gowanuss 345] Ckt 1 |
| 126285 Gothls S 345.00 126287 Gowanuss 345.00 1 | 845 | 130.8 | Loss of 126285 [Gothls S 345] - 126287 [Gowanuss 345] Ckt 1 |
| 126418 Fresh Kills 138.00 126521 Wilowbk2 138.0 1 | 202 | 100.7 | Base case |
| 130826 Meyer115 115.00 131345 S.Per115 115.00 1 | 96 | 143.0 | Loss of 130764 [Meyer230 230] - 130861 [S Perry 230] Ckt 1 |
| 135458 Ni.B-181 115.00 135460 Pack(N)E 115.00 1 | 166 | 110.9 | T:79&80 |
| 135460 Pack(N)E 115.00 147850 Niag115e 115.00 2 | 275 | 114.3 | T:61&191 |

| Monitored Element | Normal or LTE Rating (MVA) | Loading % | Contingency |
|---|---|---|---|
| 136052 Wetzel14 115.00 136181 Clay 115.00 1 | 120 | 132.0 | Sb:Oswe_R985 |
| 136052 Wetzel14 115.00 136192 Elect Pk 115.00 1 | 120 | 101.5 | Sb:Oswe_R985 |
| 137229 Kelsey H 115.00 137235 Porter 1 115.00 1 | 120 | 100.1 | B:Porter115d |
| 137481 Jmc1+7tp 115.00 137490 Bluecirc 115.00 1 | 120 | 106.8 | T:34&42b_Ce18/Uc30 |
| 137532 Rtrdm1 115.00 137876 Church-W 115.00 1 | 92 | 128.3 | Sb:Port115_R8105 |
| 137876 Church-W 115.00 137911 Vail Tap 115.00 1 | 47 | 235.0 | Sb:Port115_R8105 |

**Table 3-4**
**Post Upgrades—Thermal Overloads in the NYISO Area, Summer 2025 Case**

| Monitored Element | Normal or LTE Rating (MVA) | Loading % | Contingency |
|---|---|---|---|
| 125040 N.Cat. 1 115.00 137507 Boc 2t 115.00 2 | 120 | 103.1 | D557:Sb:Hurl345 |
| 126418 Fresh Kills 138.0 126521 Wilowbk2 138.0 1 | 202 | 100.7 | Base case |
| 137481 Jmc1+7tp 115.0 137490 Bluecirc 115.0 1 | 120 | 104.6 | T:34&42a_Ce18/Uc30 |
| 137876 Church-W 115 137911 Vail Tap 115.0 1 | 47 | 235.0 | Sb:Port115_R8105 |

**Table 3-5**
**Pre Upgrades—Thermal Overloads in the NYISO Area, Winter 2025 Case**

| Monitored Element | Normal or LTE Rating (MVA) | Loading % | Contingency |
|---|---|---|---|
| 126274 E13st 47 345.0 147829 Astor345 345.0 1 | 675 | 108.3 | Loss of 126275 [E13st 48 345] - 147829 [Astor345 345] Ckt 1 |
| 126275 E13st 48 345.0 147829 Astor345 345.0 1 | 675 | 108.3 | Loss of 126274 [E13st 47 345] - 147829 [Astor345 345] Ckt 1 |
| 130826 Meyer115 115.0 131345 S.Per115 115.0 1 | 116 | 100.4 | Loss of 130764 [Meyer230 230] - 130861 [S Perry 230] Ckt 1 |

**Table 3-6**
**Post Upgrades—Thermal Overloads in the NYISO Area, Winter 2025 Case**

| Monitored Element | Normal or LTE Rating (MVA) | Loading % | Contingency |
|---|---|---|---|
| 130862 W.Wdb115 115.0 131560 W.Wdbr69 69.0 1 | 50 | 112.3 | T:34&42b_Ce18/Uc30 |
| 135268 Clvb-141 115.00 135292 Shaltntp 115.00 1 | 117 | 107.1 | T:73&74 |
| 135268 Clvb-141 115.00 135483 S55-141 115.00 1 | 117 | 113.3 | T:73&74 |
| 135269 Clvb-142 115.00 135445 Ford-142 115.00 1 | 117 | 115.1 | T:73&74 |
| 135269 Clvb-142 115.00 135569 Lakeview 115.00 1 | 117 | 109.0 | T:73&74 |
| 135292 Shaltntp 115.00 135579 Lakev141 115.00 1 | 117 | 105.2 | T:73&74 |
| 135445 Ford-142 115.00 135484 S55-142 115.00 1 | 117 | 115.6 | T:73&74 |
| 135450 Grdnvl1 115.00 135475 S139-141 115.00 1 | 117 | 114.7 | T:73&74 |
| 135475 S139-141 115.00 135483 S55-141 115.00 1 | 117 | 113.7 | T:73&74 |

## Independent Electricity System Operator

**Table 3-7**
**Thermal Overloads in the IESO Area, Summer 2025 Case**

| Monitored Element | Normal or LTE Rating (MVA) | Loading % | Contingency |
|---|---|---|---|
| 152020 Cliffs_Hvbus220.00 152054 Hanmer_Ts 220.00 2 | 133.4 | 211.7 | Loss of 152020 [Cliffs_Hvbus220.00] - 152054 [Hanmer_Ts 220.00] Ckt 1 |
| 152055 Martindale 220.00 152093 Pedley_J 220.00 1 | 182.9 | 103.0 | Loss of 152058 [O_Holden_Ts 220.00] - 153050 [Des_Joachims220.00] Ckt 1 |
| 152093 Pedley_J 220.00 152108 Widdifield 220.00 1 | 182.9 | 103.0 | Loss of 152058 [O_Holden_Ts 220.00] - 153050 [Des_Joachims220.0] Ckt 1 |
| 152214 Carmich_Fl_J118.05 152251 Fauquier_J 118.05 1 | 96.1 | 149.4 | Loss of 152087 [Lit_Long_Jl2220.00] - 152088 [Lit_Long_Ss 220.00] Ckt 1 |
| 152214 Carmich_Fl_J118.05 152332 Spruc_F_Jh9k118.05 1 | 59.3 | 254.9 | Loss of 152087 [Lit_Long_Jl2220.00] - 152088 [Lit_Long_Ss 220.00] Ckt 1 |
| 152229 Dane_J_D3k 118.05 152299 Nine_Milejd3118.05 1 | 112.5 | 101.0 | Loss of 152057 [Anson_J91-94220.00] - 152083 [Hoyle_J 220.00] Ckt 1 |
| 152229 Dane_J_D3k 118.05 152305 Gull_Lk_Sjd3118.05 1 | 112.5 | 101.6 | Loss of 152057 [Anson_J91-94220.00] - 152083 [Hoyle_J 220.00] Ckt 1 |
| 152251 Fauquier_J 118.05 152284 Gem_Sm_Rk_J 118.05 1 | 73.6 | 193.4 | Loss of 152087 [Lit_Long_Jl2220.00] - 152088 [Lit_Long_Ss 220.00] Ckt 1 |
| 152261 Hunta_Ss 118.05 152343 Tisdale_J 118.05 1 | 108.4 | 102.9 | Loss of 152051 [Ansonville 220.00] - 152057 [Anson_J91-94220.00] Ckt 1 |
| 152261 Hunta_Ss 118.05 152349 Warkus_J 118.05 1 | 108.4 | 106.1 | Loss of 152057 [Anson_J91-94220.00] - 152083 [Hoyle_J 220.00] Ckt 1 |
| 152273 Kapuskas_Ts 118.05 152333 Spruce_Fls 118.05 1 | 145.2 | 101.4 | Loss of 152087 [Lit_Long_Jl2220.00] - 152088 [Lit_Long_Ss 220.00] Ckt 1 |
| 152284 Gem_Sm_Rk_J 118.05 152339 H9k_127a_J 118.05 1 | 96.1 | 150.6 | Loss of 152087 [Lit_Long_Jl2220.00] - 152088 [Lit_Long_Ss 220.00] Ckt 1 |
| 152322 Smooth_Rockj118.05 152339 H9k_127a_J 118.05 1 | 55.2 | 131.7 | Loss of 152087 [Lit_Long_Jl2220.00] - 152088 [Lit_Long_Ss 220.00] Ckt 1 |
| 152322 Smooth_Rockj118.05 152353 Hunta_J_H9k 118.05 1 | 55.2 | 130.2 | Loss of 152087 [Lit_Long_Jl2220.00] - 152088 [Lit_Long_Ss 220.00] Ckt 1 |
| 152339 H9k_127a_J 118.05 152353 Hunta_J_H9k 118.05 1 | 55.2 | 130.5 | Loss of 152087 [Lit_Long_Jl2220.00] - 152088 [Lit_Long_Ss 220.00] Ckt 1 |

| Monitored Element | Normal or LTE Rating (MVA) | Loading % | Contingency |
|---|---|---|---|
| 154050 Hawthorne_Ts220.00 154072 Ipb_Mas_Ja41220.00 1 | 655.4 | 121.6 | Loss of 154050 [Hawthorne_Ts220.00] - 154073 [Ipb_Mas_Ja42220.0] Ckt 1 |
| 154050 Hawthorne_Ts220.00 155114 Raisin_R_J24220.00 1 | 647.8 | 118.7 | Loss of 154072 [Ipb_Mas_Ja41220.00] - 180526 [Outhaw 220.00] Ckt 1 |
| 155049 Chats_Fls_Hq220.00 3wndtr Chatsfls T30 Wnd 1 30 | 105 | 105.7 | Loss of 154073 [Ipb_Mas_Ja42220.00] - 180526 [Outhaw 220.00] Ckt 1 |
| 155069 St_Lawrence 220.00 155114 Raisin_R_J24220.00 1 | 682.1 | 101.1 | Loss of 154072 [Ipb_Mas_Ja41220.00] - 180526 [Outhaw 220.00] Ckt 1 |
| 156018 Clrgtn220_2 220.00 156080 Duffin_J_C28220.00 1 | 224.8 | 114 | Loss of 156018 [Clrgtn220_2 220.00] - 156140 [Wilson_Jb23c220.00] Ckt 1 |
| 156324 Sithe_J_V41h220.00 156327 Sithe_Jv41h 220.00 1 | 701.1 | 119.9 | Loss of 156328 [Sithe_Jv42h 220.00] - 156336 [Sithe_Kp 220.00] Ckt 1 |
| 158206 Majestic_B22220.00 158803 Majestic_B 69.000 T1 | 55.5 | 153.8 | Loss of 158207 [Majestic_B23220.00] - 159058 [Majest_Jb23d220.00] Ckt 1 |
| 158207 Majestic_B23220.00 158803 Majestic_B 69.000 T2 | 55.5 | 153.2 | Loss of 158206 [Majestic_B22220.00] - 159057 [Majest_Jb22d220.00] Ckt 1 |
| 159011 Parkhill_Cts500.00 3wndtr Parkhill-T1 Wnd 1 T1 | 180 | 140.4 | Loss of 159011 [Parkhill_Cts500.00] - 159200 [Parkhill 118.05] - 159602 [Parkhill_T2 27.600] Ckt T2 |
| 159011 Parkhill_Cts500.00 3wndtr Parkhill-T2 Wnd 1 T2 | 180 | 140.4 | Loss of 159011 [Parkhill_Cts500.00] - 159200 [Parkhill 118.05] - 159601 [Parkhill_T1 27.600] Ckt T1 |
| 160118 Talbot_W36 220.0 3wndtr Talbott3 Wnd 1 T3 | 179.6 | 113.3 | Loss of 160119 [Talbot_W37 220.00] - 160674 [Talbot_J1j2 27.600] - 160673 [Talbot_Q1q2 27.600] Ckt T4 |
| 160137 Tr_Energyj6a220.0 160139 Tr_Energyj6b220 1 | 415.4 | 104.7 | Loss of 160138 [Tr_Energyj7a220.0] - 160140 [Tr_Energyj7b220] Ckt 1 |

**Table 3-8**
**Thermal Overloads in the IESO Area, Winter 2025 Case**

| Monitored Element | Normal or LTE Rating (MVA) | Loading % | Contingency |
|---|---|---|---|
| 152020 Cliffs_Hvbus220.00 152021 Cliffs_Furn169.000 T1 | 240 | 104.2 | Loss of 152020 [Cliffs_Hvbus220.00] - 152025W [Cliffs_Furn269.000] Ckt T3 |
| 152020 Cliffs_Hvbus220.00 152025W Cliffs_Furn269.000 T3 | 240 | 104.2 | Loss of 152020 [Cliffs_Hvbus220.00] - 152021 [Cliffs_Furn169.000] Ckt T1 |
| 152020 Cliffs_Hvbus220.00 152054 Hanmer_Ts 220.00 2 | 180 | 180.5 | Loss of 152020 [Cliffs_Hvbus220.00] - 152054 [Hanmer_Ts 220.00] Ckt 1 |
| 152069 Clarabel_S22220.00 152607 Clarabel_By 44.000 T2 | 197.2 | 144.8 | Loss of 152054 [Hanmer_Ts 220.00] - 152100 [Frd_Stobjx23220.00] Ckt 1 |
| 153086 Muskoka_M6e 220.00 153645 Muskoka_By 44.0 T2 | 168.7 | 103.6 | Loss of 153087 [Muskoka_M7e 220.00] - 153098 [Bracebrg_Jm7220.00] Ckt 1 |
| 153087 Muskoka_M7e 220.00 153645 Muskoka_By 44.0 T1 | 168.7 | 103.9 | Loss of 153086 [Muskoka_M6e 220.00] - 153100 [Bracebrg_Jm6220.00] Ckt 1 |
| 153092 Parry_Snd_26220.00 153647 Parry_Snd_By44.000 T2 | 56.5 | 105.0 | Loss of 153091 [Par_Snd_Je27220.00] - 153093 [Parry_Snd_27220.00] Ckt 1 |
| 153093 Parry_Snd_27220.00 153647 Parry_Snd_By44.000 T1 | 56.5 | 105.0 | Loss of 153090 [Par_Snd_Je26220.00] - 153092 [Parry_Snd_26220.00] Ckt 1 |
| 155094 Gardinerx4t4220.00 155742 Gardiner_Jq 44.000 T4 | 91.4 | 171.2 | Loss of 155094 [Gardinerx4t4220.00] - 155138 [Gardiner_Jx4220.00] Ckt 1 |
| 155129 Gardinerx2t3220.00 155742 Gardiner_Jq 44.000 T3 | 91.4 | 176.5 | Loss of 155094 [Gardinerx4t4220.00] - 155138 [Gardiner_Jx4220.00] Ckt 1 |
| 156324 Sithe_J_V41h220.00 156327 Sithe_Jv41h 220.00 1 | 800.2 | 111.6 | Loss of 156325 [Sithe_J_V42h220.00] - 156328 [Sithe_Jv42h 220.00] Ckt 1 |

## New Brunswick

**Table 3-9**
**Thermal Overloads in the NB Area, Summer 2025 Case**

| Monitored Element | Normal or LTE Rating (MVA) | Loading % | Contingency |
|---|---|---|---|
| 192274 Sherbrk 138.00 192275 Sherb69 69.000 1 | 30 | 124.8 | Base case |
| 192274 Sherbrk 138.00 192275 Sherb69 69.000 2 | 30 | 124.8 | Base case |
| 199042 101s-Woodbin230.00 199050 3c-Hastings 230.00 1 | 327.8 | 115.0 | Loss of 199045 [101s-Woodbin345.00] - 199120 [79n-Hopwell 345.0] Ckt 1 |

**Table 3-10**
**Thermal Overloads in the NB Area, Winter 2025 Case**

| Monitored Element | Normal or LTE Rating (MVA) | Loading % | Contingency |
|---|---|---|---|
| 190021 C.Bay 138.00 190526 Grndvw 138.00 1 | 246 | 122.9 | Loss of 190197 [C.Cove 345.00] - 190498 [Norton 345.00] Ckt 1 |
| 190198 C.Cove 138.00 190389 Mild47 138.00 1 | 202 | 109.0 | Loss of 190197 [C.Cove 345.00] - 190498 [Norton 345.00] Ckt 1 |
| 190246 Lakewd 138.00 190290 114987 138.00 1 | 246 | 105.6 | Loss of 190197 [C.Cove 345.00] - 190498 [Norton 345.00] Ckt 1 |
| 190246 Lakewd 138.00 190526 Grndvw 138.00 1 | 246 | 116.8 | Loss of 190197 [C.Cove 345.00] - 190498 [Norton 345.00] Ckt 1 |
| 190342 119977 138.00 190499 Norton 138.00 1 | 246 | 111.5 | Loss of 190320 [Salbry 345.00] - 190498 [Norton 345.00] Ckt 1 |

## Midcontinent Independent System Operator

**Table 3-11**
**Pre Upgrades—Thermal Overloads in the MISO Area, Summer 2025 Case**

| Monitored Element | Normal or LTE Rating (MVA) | Loading % | Contingency |
|---|---|---|---|
| 256016 18mcv 345.00 256027 18titbaw 345.00 1 | 1,691 | 109.4 | Loss of 256016 [18mcv 345.00] - 256027 [18titbaw 345.00] Ckt 2 |
| 256016 18mcv 345.00 256027 18titbaw 345.00 2 | 1,616 | 114.4 | Loss of 256016 [18mcv 345.00] - 256027 [18titbaw 345.00] Ckt 1 |
| 256201 18lvnstn 138.00 256202 18livpkr 138.00 1 | 136 | 103.0 | Base case |
| 335136 6ppg! 230.00 338996 6nsub1% 230.00 1 | 470 | 102.8 | Loss of 335136 [6ppg! 230.00] - 338995 [6nsub2% 230.00] Ckt 1 |
| 335387 4delcambre138.00 335388 4moril! 138.00 1 | 191 | 125.1 | Loss of 335381 [6meaux! 230.00] - 335380 [4meaux! 138.0] Ckt 1 |
| 337310 3beaver_Crk!115.00 500070 Bc Pst 4 138.00 1 | 93 | 114.6 | Loss of 500200 [Colfax 6 230.00] - 500770 [Rodemr 6 230.00] Ckt 1 |
| 337905 5russelvl.E!161.00 337906 5russelvl.N 161.00 1 | 396 | 107.6 | Loss of 337909 [8ano% 500.00] - 515305 [Ftsmith8 500.00] Ckt 1 |
| 500280 Eleesv 6 230.00 500770 Rodemr 6 230.00 1 | 416 | 110.0 | Loss of 500200 [Colfax 6 230.00] - 500770 [Rodemr 6 230.00] Ckt 1 |
| 602006 Sheynne4 230.00 652435 Fargo 4 230.00 1 | 342 | 106.2 | Loss of 620358 [Buffalo3 345.00] - 620369 [Jamestn3 345] Ckt 1 |
| 603018 Sheynne7 115.00 620203 Mapltn 7 115.00 1 | 162 | 105.1 | Loss of 601067 [Bison 3 345.00] - 620358 [Buffalo3 345.00] Ckt 1 |
| 608666 Fondulac 115.00 608676 Hibbard7 115.00 1 | 44 | 110.6 | Loss of 608614 [98l Tap4 230.00] - 608622 [Ironrng4 230] Ckt 1 |
| 615560 Gre-Wst Cld7115.00 3wndtr 115/69 Wnd 2 1 | 45.1 | 104.1 | Loss of 619975 [Gre-Willmar4230.00] - 652550 [Granitf4 230.00] Ckt 1 |
| 652391 Williston27 115.00 661089 Ltlmudy7 115.00 1 | 102 | 100.7 | Loss of 659362 [Wheelock 4230.00] - 661084 [Tioga4 4 230.00] Ckt 1 |
| 652417 Dicknsn4 230.00 3wndtr Kw1a 100 Wnd 1 1 | 120 | 102.2 | Loss of 652425 [Belfeld4 230.00] - 659266 [Rhame 4 230] Ckt 1 |
| 652443 Grndfks7 115.00 657706 Falconr7 115.00 1 | 125.5 | 125.4 | Loss of 657758 [Winger 4 230.00] - 62025W8 [Winger 7 115.0] - 620338 [Winger19 13.200] Ckt 1 |

| Monitored Element | Normal or LTE Rating (MVA) | Loading % | Contingency |
|---|---|---|---|
| 652510 Ftrandl7 115.00 640349 Spencer7 115.00 1 | 120.7 | 104.0 | Loss of 652509 [Ftrandl4 230.0] - 652526 [Uticajc4 230.00] Ckt 1 |
| 657712 Prairie7 115.00 657904 Prairie8 69.000 3 | 80.5 | 102.3 | Loss of 652437 [Grndfks4 230.00] - 652443 [Grndfks7 115.00] - 652201 [Grndfks9 12.470] Ckt 1 |
| 661008 Beulah 7 115.00 661018 Coyote 7 115.00 1 | 102 | 263.4 | Loss of 657791 [Center 3 345.0] - 661016 [Coyote 3 345.0] Ckt 1 |
| 661008 Beulah 7 115.00 661054 Mandan 7 115.00 1 | 88 | 172.2 | Loss of 657791 [Center 3 345.0] - 661016 [Coyote 3 345.0] Ckt 1 |
| 661016 Coyote 3 345.0 3wndtr Coyote Tr1 Wnd 1 1 | 210 | 211.4 | Loss of 657791 [Center 3 345.0] - 661016 [Coyote 3 345.0] Ckt 1 |
| 661018 Coyote 7 115.0 3wndtr Coyote Tr1wnd 2 1 | 210 | 202.1 | Loss of 657791 [Center 3 345.0] - 661016 [Coyote 3 345.0] Ckt 1 |
| 661018 Coyote 7 115.00 661021 Wstmd1 7 115.00 1 | 102 | 154.7 | Loss of 657791 [Center 3 345.0] - 661016 [Coyote 3 345.0] Ckt 1 |
| 661020 Dixgreenrvr7115.0 661021 Wstmd1 7 115.0 1 | 102 | 148.8 | Loss of 657791 [Center 3 345.0] - 661016 [Coyote 3 345.0] Ckt 1 |
| 661035 Glenham7 115.0 3wndtr Glenham Tr1 Wnd 2 1 | 31 | 125.5 | Loss of 661038 [Glenham4 230.00] - 661035 [Glenham7 115.00] - 661600 [Glenham9 41.600] Ckt 2 |
| 661038 Glenham4 230.0 3wndtr Glenham Tr1 Wnd 11 | 38 | 148.3 | Loss of 661038 [Glenham4 230.00] - 661035 [Glenham7 115.00] - 661600 [Glenham9 41.600] Ckt 2 |
| 667001 Henday 4 230.00 667003 Limest44 230.00 4 | 160.1 | 164.0 | Base case |
| 667001 Henday 4 230.00 667004 Limest34 230.00 3 | 160.1 | 164.0 | Base case |
| 667001 Henday 4 230.00 667005 Limest24 230.00 2 | 160.1 | 163.9 | Base case |
| 667001 Henday 4 230.00 667006 Limest14 230.00 1 | 160.1 | 163.7 | Base case |
| 667027 Wilrivr4 230.00 667028 Gr.Rpds4 230.00 1 | 226.3 | 121.2 | Loss of 667059 [Rall 4 230.0] - 667060 [Overflo4 230.0] Ckt 1 |
| 667027 Wilrivr4 230.00 669820 Ponton 4 230.00 1 | 226.3 | 118.9 | Loss of 667059 [Rall 4 230.0] - 667060 [Overflo4 230.0] Ckt 1 |
| 667059 Rall 4 230.00 667060 Overflo4 230.00 1 | 226.3 | 119.6 | Loss of 667027 [Wilrivr4 230.0] - 669820 [Ponton 4 230.0] Ckt 1 |

| Monitored Element | Normal or LTE Rating (MVA) | Loading % | Contingency |
|---|---|---|---|
| 667226 Rad_K3_6 138.0 667231 Radsndc6 138.00 3 | 282.8 | 142.7 | Loss of 667001 [Henday 4 230.0] - 667003 [Limest44 230.0] Ckt 4 |
| 668015 Mr11 T 7 110.00 668064 Ravlake7 110.00 1 | 81.2 | 106.5 | Loss of 667064 [Ravlake4 230.0] - 667065 [Birtle 4 230.00] Ckt 1 |
| 668038 Rosser 7 110.00 668113 Inkster7 110.00 1 | 115.8 | 120.4 | Base case |
| 668065 Selkirk7 110.00 668066 Mercyst7 110.00 1 | 93.2 | 107.8 | Loss of 667080 [Rockwd 4 230] - 668133 [Rockwd 7 110.0] Ckt 1 |
| 672512 Condie 6 138.00 672612 Condie 4 230.00 1 | 235 | 102.9 | Loss of 672612 [Condie 4 230.0] - 672512 [Condie 6 138.0] Ckt 2 |
| 672512 Condie 6 138.00 672612 Condie 4 230.00 2 | 225 | 107.4 | Loss of 672612 [Condie 4 230.0] - 672512 [Condie 6 138.0] Ckt 1 |
| 672515 Yorkton6 138.00 672615 Yorkton4 230.00 1 | 143.4 | 112.1 | Loss of 672610 [Poplar 4 230.0] - 672311 [Poplar2g 18.0] Ckt 1 |
| 699687 Glory Rd2 138.00 699994 Depere 138.00 1 | 246 | 108.4 | Loss of 694029 [Hiway 22 B2 345] - 694034 [Morgan B3 345] Ckt 1 |

**Table 3-12**
**Post Upgrades—Thermal Overloads in the MISO Area, Summer 2025 Case**

| Monitored Element | Normal or LTE Rating (MVA) | Loading % | Contingency |
|---|---|---|---|
| 337310 3beaver_Crk!115.00 500070 Bc Pst 4 138.00 1 | 93 | 112.6 | Loss of 500200 [Colfax 6 230.00] - 500770 [Rodemr 6 230.00] Ckt 1 |
| 652391 Williston27 115.00 661089 Ltlmudy7 115.00 1 | 102 | 100.7 | Loss of 659362 [Wheelock 4230.0] - 661084 [Tioga4 4 230] Ckt 1 |
| 652443 Grndfks7 115.00 657706 Falconr7 115.00 1 | 125.5 | 125.3 | Loss of 657758 [Winger 4 230.00] - 62025W8 [Winger 7 115.00] - 620338 [Winger19 13.200] Ckt 1 |
| 652510 Ftrandl7 115.00 640349 Spencer7 115.00 1 | 120.7 | 104.0 | Loss of 652509 [Ftrandl4 230.00] - 652526 [Uticajc4 230.00] Ckt 1 |
| 657712 Prairie7 115.00 657904 Prairie8 69.000 3 | 80.5 | 101.7 | Loss of 652437 [Grndfks4 230.00] - 652443 [Grndfks7 115.00] - 652201 [Grndfks9 12.470] Ckt 1 |
| 661008 Beulah 7 115.00 661018 Coyote 7 115.00 1 | 102 | 261.3 | Loss of 657791 [Center 3 345.00] - 661016 [Coyote 3 345.0] Ckt 1 |

| Monitored Element | Normal or LTE Rating (MVA) | Loading % | Contingency |
|---|---|---|---|
| 661008 Beulah 7 115.00 661054 Mandan 7 115.00 1 | 88 | 170.1 | Loss of 657791 [Center 3 345.00] - 661016 [Coyote 3 345.0] Ckt 1 |
| 661016 Coyote 3 345.00 3wndtr Coyote Tr1 Wnd 1 1 | 210 | 210.2 | Loss of 657791 [Center 3 345.00] - 661016 [Coyote 3 345.0] Ckt 1 |
| 661018 Coyote 7 115.00 3wndtr Coyote Tr1 Wnd 2 1 | 210 | 202.5 | Loss of 657791 [Center 3 345.00] - 661016 [Coyote 3 345.0] Ckt 1 |
| 661018 Coyote 7 115.00 661021 Wstmd1 7 115.00 1 | 102 | 156.6 | Loss of 657791 [Center 3 345.00] - 661016 [Coyote 3 345.0] Ckt 1 |
| 661020 Dixgreenrvr7115.00 661021 Wstmd1 7 115.00 1 | 102 | 151.1 | Loss of 657791 [Center 3 345.00] - 661016 [Coyote 3 345.0] Ckt 1 |
| 661035 Glenham7 115.00 3wndtr Glenham Tr1 Wnd 2 1 | 31 | 125.6 | Loss of 661038 [Glenham4 230.00] - 661035 [Glenham7 115.00] - 661600 [Glenham9 41.600] Ckt 2 |
| 661038 Glenham4 230.00 3wndtr Glenham Tr1 Wnd 1 1 | 38 | 148.4 | Loss of 661038 [Glenham4 230.00] - 661035 [Glenham7 115.00] - 661600 [Glenham9 41.600] Ckt 2 |
| 667001 Henday 4 230.00 667003 Limest44 230.00 4 | 160.1 | 164.0 | Base case |
| 667001 Henday 4 230.00 667004 Limest34 230.00 3 | 160.1 | 164.0 | Base case |
| 667001 Henday 4 230.00 667005 Limest24 230.00 2 | 160.1 | 163.9 | Base case |
| 667001 Henday 4 230.00 667006 Limest14 230.00 1 | 160.1 | 163.7 | Base case |
| 667027 Wilrivr4 230.00 667028 Gr.Rpds4 230.00 1 | 226.3 | 121.2 | Loss of 667059 [Rall 4 230.0] - 667060 [Overflo4 230.00] Ckt 1 |
| 667027 Wilrivr4 230.00 669820 Ponton 4 230.00 1 | 226.3 | 118.9 | Loss of 667059 [Rall 4 230.0] - 667060 [Overflo4 230.00] Ckt 1 |
| 667059 Rall 4 230.00 667060 Overflo4 230.00 1 | 226.3 | 119.8 | Loss of 667027 [Wilrivr4 230.0] - 667028 [Gr.Rpds4 230.0] Ckt 1 |
| 667226 Rad_K3_6 138.00 667231 Radsndc6 138.00 3 | 282.8 | 153.3 | Loss of 667001 [Henday 4 230.0] - 667003 [Limest44 230.0] Ckt 4 |
| 668015 Mr11 T 7 110.00 668064 Ravlake7 110.00 1 | 81.2 | 106.6 | Loss of 667064 [Ravlake4 230.0] - 667065 [Birtle 4 230.00] Ckt 1 |
| 668038 Rosser 7 110.00 668113 Inkster7 110.00 1 | 115.8 | 120.4 | Base case |
| 668065 Selkirk7 110.00 668066 Mercyst7 110.00 1 | 93.2 | 107.8 | Loss of 667080 [Rockwd 4 230.0] - 668133 [Rockwd 7 110.0] Ckt 1 |

| Monitored Element | Normal or LTE Rating (MVA) | Loading % | Contingency |
|---|---|---|---|
| 672512 Condie 6 138.00 672612 Condie 4 230.00 1 | 235 | 102.9 | Loss of 672612 [Condie 4 230.0] - 672512 [Condie 6 138.0] Ckt 2 |
| 672512 Condie 6 138.00 672612 Condie 4 230.00 2 | 225 | 107.4 | Loss of 672612 [Condie 4 230.0] - 672512 [Condie 6 138.0] Ckt 1 |
| 672515 Yorkton6 138.00 672615 Yorkton4 230.00 1 | 143.4 | 112.3 | Loss of 672610 [Poplar 4 230.00] - 672310 [Poplar1g 18.00] Ckt 1 |

**Table 3-13**
**Pre Upgrades—Thermal Overloads in the MISO Area, Winter 2025 Case**

| Monitored Element | Normal or LTE Rating (MVA) | Loading % | Contingency |
|---|---|---|---|
| 334333 4newtonb! 138.00 334334 4leach, 138.00 1 | 145 | 122.8 | Loss of 334325 [8hartbrg% 500.0] - 509366 [Layfld8 500.0] Ckt 1 |
| 335136 6ppg! 230.00 338996 6nsub1% 230.00 1 | 470 | 117.6 | Loss of 335136 [6ppg! 230.00] - 338995 [6nsub2% 230.00] Ckt 1 |
| 500050 Bsales 4 138.00 500820 Teche 4 138.00 1 | 289 | 109.1 | Loss of 335368 [8wells% 500.00] - 335500 [8webre% 500.0] Ckt 1 |
| 500050 Bsales 4 138.00 500890 Waxlake4 138.00 1 | 289 | 113.4 | Loss of 335368 [8wells% 500.00] - 335500 [8webre% 500.0] Ckt 1 |
| 500060 Bvista 4 138.00 500290 Elptap 4 138.00 1 | 289 | 123.5 | Loss of 335368 [8wells% 500.00] - 335500 [8webre% 500.0] Ckt 1 |
| 500280 Eleesv 6 230.00 500770 Rodemr 6 230.00 1 | 416 | 106.6 | Loss of 335368 [8wells% 500.00] - 335500 [8webre% 500.0] Ckt 1 |
| 500290 Elptap 4 138.00 500890 Waxlake4 138.00 1 | 289 | 119.2 | Loss of 335368 [8wells% 500.00] - 335500 [8webre% 500.0] Ckt 1 |
| 608650 Littlef7 115.00 617000 Gre-Langltp7115.00 1 | 132 | 108.0 | Loss of 601016 [Chis Co2 500.00] - 601017 [Chis-N 2 500] Ckt 1 |
| 608651 Mudlake7 115.00 608652 Brainrd7 115.00 1 | 132 | 124.8 | Loss of 608612 [Rivertn4 230.00] - 608617 [Mudlake4 230] Ckt 1 |
| 615335 Gre-Ramsey 4230 3wndtr Ram230115-1 Wnd 1 1 | 140 | 102.5 | Loss of 615335 [Gre-Ramsey 4230.00] - 657755 [Prairie4 230.0] Ckt 1 |
| 615560 Gre-Wst Cld7115 619410 Gre-Lsauktp7115.00 1 | 159.3 | 108.5 | Loss of 601001 [Forbes 2 500.00] - 601017 [Chis-N 2 500.0] Ckt 1 |

| Monitored Element | Normal or LTE Rating (MVA) | Loading % | Contingency |
|---|---|---|---|
| 62025W8 Winger 7 115.00 3wndtr 230/115 Wnd 2 1 | 166 | 102.5 | Base case |
| 620266 Ramsey 7 115 3wndtr Ram230-115-1 Wnd 2 1 | 140 | 102.3 | Loss of 615335 [Gre-Ramsey 4230.00] - 657755 [Prairie4 230.0] Ckt 1 |
| 620327 Hankson4 230.00 620329 Wahpetn4 230.00 1 | 351 | 100.3 | Loss of 620358 [Buffalo3 345.00] - 620369 [Jamestn3 345.0] Ckt 1 |
| 652417 Dicknsn4 230.00 3wndtr Kw1a 100 Wnd 1 1 | 120 | 100.7 | Loss of 661047 [Hetingr4 230.00] - 661048 [Hetingr7 115] - 661902 [Hetingr9 13.800] Ckt 1 |
| 652431 Devilsl7 115.00 652465 Penn 7 115.00 1 | 111 | 100.3 | Loss of 615335 [Gre-Ramsey 4230.00] - 615903 [Gre-Balta 4230] Ckt 1 |
| 652435 Fargo 4 230.00 3wndtr Fa Kv1a Wnd 1 1 | 125 | 115.0 | Loss of 652435 [Fargo 4 230.00] - 652436 [Fargo 7 115.00] - 652434 [Fargosvc 13.200] Ckt 2 |
| 652436 Fargo 7 115.00 3wndtr Fa Kv1a Wnd 2 1 | 125 | 117.3 | Loss of 652435 [Fargo 4 230.00] - 652436 [Fargo 7 115.00] - 652434 [Fargosvc 13.200] Ckt 2 |
| 652443 Grndfks7 115.00 657706 Falconr7 115.00 1 | 170.9 | 152.9 | Loss of 657752 [Drayton4 230.00] - 657755 [Prairie4 230.0] Ckt 1 |
| 652446 Pleasant Lk7115.00 652447 Leeds 7 115.00 1 | 132 | 108.9 | Loss of 615335 [Gre-Ramsey 4230.0] - 615903 [Gre-Balta 4230.0] Ckt 1 |
| 652446 Pleasant Lk7115.00 652452 Rugby 7 115.00 1 | 132 | 112.1 | Loss of 615335 [Gre-Ramsey 4230.00] - 615903 [Gre-Balta 4230.] Ckt 1 |
| 652447 Leeds 7 115.00 652465 Penn 7 115.00 1 | 111 | 100.9 | Loss of 615335 [Gre-Ramsey 4230.0] - 615903 [Gre-Balta 4230.0] Ckt 1 |
| 652452 Rugby 7 115.00 659665 Rugby Tap 7115.00 Z | 79.7 | 109.6 | Loss of 615335 [Gre-Ramsey 4230.0] - 615903 [Gre-Balta 4230.0] Ckt 1 |
| 657706 Falconr7 115.00 657722 Oslo 7 115.00 1 | 146 | 144.4 | Loss of 657752 [Drayton4 230.00] - 657755 [Prairie4 230.00] Ckt 1 |
| 657712 Prairie7 115.00 3wndtr Prairie #2 Wnd 1 2 | 88 | 105.1 | Loss of 652437 [Grndfks4 230.00] - 652443 [Grndfks7 115.00] - 652201 [Grndfks9 12.470] Ckt 1 |
| 657757 Moranvi4 230.00 3wndtr Moranville # Wnd 1 2 | 80 | 125.2 | Loss of 602013 [Roseau 4 230.0] - 657757 [Moranvi4 230.0] Ckt 1 |
| 657758 Winger 4 230.00 3wndtr 230/115 Wnd 1 1 | 166 | 104.6 | Base case |
| 659640 Chrrycrk-Mk7115.0 659641 Arnegard-Mk7115.0 1 | 120 | 103.2 | Base case |

| Monitored Element | Normal or LTE Rating (MVA) | Loading % | Contingency |
|---|---|---|---|
| 661008 Beulah 7 115.00 661018 Coyote 7 115.00 1 | 123 | 217.9 | Loss of 657791 [Center 3 345.0] - 661016 [Coyote 3 345.0] Ckt 1 |
| 661008 Beulah 7 115.00 661054 Mandan 7 115.00 1 | 106 | 138.5 | Loss of 657791 [Center 3 345.0] - 661016 [Coyote 3 345.0] Ckt 1 |
| 661016 Coyote 3 345.00 3wndtr Coyote Tr1 Wnd 1 1 | 210 | 210.9 | Loss of 657791 [Center 3 345.0] - 661016 [Coyote 3 345.0] Ckt 1 |
| 661018 Coyote 7 115.00 3wndtr Coyote Tr1 Wnd 2 1 | 210 | 202/0 | Loss of 657791 [Center 3 345.0] - 661016 [Coyote 3 345.0] Ckt 1 |
| 661018 Coyote 7 115.00 661021 Wstmd1 7 115.00 1 | 123 | 128.4 | Loss of 657791 [Center 3 345.0] - 661016 [Coyote 3 345.0] Ckt 1 |
| 661020 Dixgreenrvr7115.00 661021 Wstmd1 7 115 1 | 123 | 123.6 | Loss of 657791 [Center 3 345.0] - 661016 [Coyote 3 345.0] Ckt 1 |
| 661035 Glenham7 115 3wndtr Glenham Tr1 Wnd 2 1 | 31 | 123.7 | Loss of 661038 [Glenham4 230.00] - 661035 [Glenham7 115.00] - 661600 [Glenham9 41.600] Ckt 2 |
| 661038 Glenham4 230 3wndtr Glenham Tr1 Wnd 1 1 | 38 | 142.5 | Loss of 661038 [Glenham4 230.00] - 661035 [Glenham7 115.00] - 661600 [Glenham9 41.600] Ckt 2 |
| 667001 Henday 4 230.00 667004 Limest34 230.00 3 | 190 | 128/0 | Base case |
| 667001 Henday 4 230.00 667005 Limest24 230.00 2 | 190 | 128.0 | Base case |
| 667001 Henday 4 230.00 667006 Limest14 230.00 1 | 190 | 127.9 | Base case |
| 667226 Rad_K3_6 138.00 667231 Radsndc6 138.00 3 | 369.3 | 114.5 | Loss of 667001 [Henday 4 230.00] - 667004 [Limest34 230.00] Ckt 3 |
| 672501 Bd 6 138.00 672601 Bd 4 230.00 1 | 250 | 100.3 | Loss of 672601 [Bd 4 230.00] - 672501 [Bd 6 138.00] Ckt 2 |
| 672501 Bd 6 138.00 672601 Bd 4 230.00 2 | 250 | 100.3 | Loss of 672601 [Bd 4 230.00] - 672501 [Bd 6 138.00] Ckt 1 |
| 672512 Condie 6 138.00 672612 Condie 4 230.00 1 | 235 | 100.0 | Loss of 672612 [Condie 4 230.0] - 672512 [Condie 6 138.0] Ckt 2 |
| 672512 Condie 6 138.00 672612 Condie 4 230.00 2 | 225 | 104.5 | Loss of 672612 [Condie 4 230.0] - 672512 [Condie 6 138.0] Ckt 1 |
| 672515 Yorkton6 138.00 672615 Yorkton4 230.00 1 | 143.4 | 108.4 | Loss of 672610 [Poplar 4 230.00] - 672310 [Poplar1g 18.0] Ckt 1 |
| 698857 Oc Crk8 230.00 699367 Elm Road 345.00 1 | 300 | 102.4 | Loss of 698856 [Oc Crk7 230.00] - 699370 [Oc Crk6 230.0] Ckt Z |

**Table 3-14**
**Post Upgrades—Thermal Overloads in the MISO Area, Winter 2025 Case**

| Monitored Element | Normal or LTE Rating (MVA) | Loading % | Contingency |
|---|---|---|---|
| 652435 Fargo 4 230.00 3wndtr Fa Kv1a Wnd 1 1 | 125 | 113.0 | Loss of 652435 [Fargo 4 230.00] - 652436 [Fargo 7 115.00] - 652434 [Fargosvc 13.200] Ckt 2 |
| 652436 Fargo 7 115.00 3wndtr Fa Kv1a Wnd 2 1 | 125 | 115.8 | Loss of 652435 [Fargo 4 230.00] - 652436 [Fargo 7 115.00] - 652434 [Fargosvc 13.200] Ckt 2 |
| 652443 Grndfks7 115.00 657706 Falconr7 115.00 1 | 170.9 | 125.7 | Loss of 657752 [Drayton4 230.0] - 657755 [Prairie4 230.0] Ckt 1 |
| 652446 Pleasant Lk7115.00 652447 Leeds 7 115.00 1 | 132 | 107.5 | Loss of 615335 [Gre-Ramsey 4230.00] - 615903 [Gre-Balta 4230.0] Ckt 1 |
| 652446 Pleasant Lk7115.0 652452 Rugby 7 115.00 1 | 132 | 110.4 | Loss of 615335 [Gre-Ramsey 4230.00] - 615903 [Gre-Balta 4230.0] Ckt 1 |
| 652447 Leeds 7 115.00 652465 Penn 7 115.00 1 | 111 | 100.4 | Loss of 615335 [Gre-Ramsey 4230.00] - 615903 [Gre-Balta 4230.0] Ckt 1 |
| 657706 Falconr7 115.00 657722 Oslo 7 115.00 1 | 146 | 112.4 | Loss of 657752 [Drayton4 230.0] - 657755 [Prairie4 230.0] Ckt 1 |
| 657757 Moranvi4 230.00 3wndtr Moranville # Wnd 1 2 | 80 | 108.9 | Loss of 602012 [Rosswcp4 230] - 602013 [Roseau 4 230] Ckt Z |
| 659640 Chrrycrk-Mk7115 659641 Arnegard-Mk7115 1 | 120 | 103.2 | Base case |
| 661008 Beulah 7 115.00 661018 Coyote 7 115.00 1 | 123 | 217.2 | Loss of 657791 [Center 3 345.0] - 661016 [Coyote 3 345.0] Ckt 1 |
| 661008 Beulah 7 115.00 661054 Mandan 7 115.00 1 | 106 | 137.5 | Loss of 657791 [Center 3 345.0] - 661016 [Coyote 3 345.0] Ckt 1 |
| 661016 Coyote 3 345.00 3wndtr Coyote Tr1 Wnd 1 1 | 210 | 210.4 | Loss of 657791 [Center 3 345.0] - 661016 [Coyote 3 345.0] Ckt 1 |
| 661018 Coyote 7 115.00 3wndtr Coyote Tr1 Wnd 2 1 | 210 | 202.5 | Loss of 657791 [Center 3 345.0] - 661016 [Coyote 3 345.0] Ckt 1 |
| 661018 Coyote 7 115.00 661021 Wstmd1 7 115.00 1 | 123 | 129.3 | Loss of 657791 [Center 3 345.0] - 661016 [Coyote 3 345.0] Ckt 1 |

| Monitored Element | Normal or LTE Rating (MVA) | Loading % | Contingency |
|---|---|---|---|
| 661020 Dixgreenrvr7115.0 661021 Wstmd1 7 115.0 1 | 123 | 124.7 | Loss of 657791 [Center 3 345.0] - 661016 [Coyote 3 345.0] Ckt 1 |
| 661035 Glenham7 115.0 3wndtr Glenham Tr1 Wnd 2 1 | 31 | 123.9 | Loss of 661038 [Glenham4 230.00] - 661035 [Glenham7 115.00] - 661600 [Glenham9 41.600] Ckt 2 |
| 661038 Glenham4 230.0 3wndtr Glenham Tr1 Wnd 1 1 | 38 | 142.6 | Loss of 661038 [Glenham4 230.00] - 661035 [Glenham7 115.00] - 661600 [Glenham9 41.600] Ckt 2 |
| 667001 Henday 4 230.00 667004 Limest34 230.00 3 | 190 | 128.0 | Base case |
| 667001 Henday 4 230.00 667005 Limest24 230.00 2 | 190 | 128.0 | Base case |
| 667001 Henday 4 230.00 667006 Limest14 230.00 1 | 190 | 127.9 | Base case |
| 667226 Rad_K3_6 138.00 667231 Radsndc6 138.00 3 | 369.3 | 114.5 | Loss of 667001 [Henday 4 230.00] - 667004 [Limest34 230.00] Ckt 3 |
| 672501 Bd 6 138.0 672601 Bd 4 230.0 1 | 250 | 100.3 | Loss of 672601 [Bd 4 230.00] - 672501 [Bd 6 138.00] Ckt 2 |
| 672501 Bd 6 138.00 672601 Bd 4 230.00 2 | 250 | 100.3 | Loss of 672601 [Bd 4 230.00] - 672501 [Bd 6 138.00] Ckt 1 |
| 672512 Condie 6 138.00 672612 Condie 4 230.00 1 | 235 | 100.0 | Loss of 672612 [Condie 4 230.00] - 672512 [Condie 6 138.00] Ckt 2 |
| 672512 Condie 6 138.00 672612 Condie 4 230.00 2 | 225 | 104.5 | Loss of 672612 [Condie 4 230.00] - 672512 [Condie 6 138.00] Ckt 1 |
| 672515 Yorkton6 138.00 672615 Yorkton4 230.00 1 | 143.4 | 108.5 | Loss of 672610 [Poplar 4 230.00] - 672310 [Poplar1g 18.0] Ckt 1 |

## PJM Interconnection

**Table 3-15**
**Thermal Overloads in the PJM Area, Summer 2025 Case**

| Monitored Element | Normal or LTE Rating (MVA) | Loading % | Contingency |
|---|---|---|---|
| 208105 Stee Tr1 230.00 208107 Stee 69.000 1 | 75 | 107.7 | Pl100475 |
| 208106 Stee Tr3 230.00 208107 Stee 69.000 3 | 75 | 131.2 | Pl100475 |
| 223992 Hawk 076 230.00 224078 Hawk 69 69.000 1 | 275 | 101.1 | Pp53 |
| 223993 Hawk 077 230.00 224078 Hawk 69 69.000 1 | 275 | 101.6 | Pp54_B |
| 232203 Churc_69 69.000 232810 Massyrea 69.000 1 | 64 | 127.9 | Ckt 6773 |
| 271321 Devon ;6r138.00 272129 Northwest; R138.00 1 | 253 | 101.5 | 088-L8803___ |
| 271322 Devon ;9b138.00 272384 Rose Hill;Bt138.00 1 | 270 | 111.6 | 088-L8810___ |
| 271322 Devon ;9b138.00 272470 Skokie 85;9t138.00 1 | 332 | 102.3 | 088-L8810___ |
| 271323 Devon ;3r138.00 272385 Rose Hill;Rt138.00 1 | 270 | 114.1 | 088-L11416__ |
| 271324 Devon ;0b138.00 272128 Northwest; B138.00 1 | 270 | 115.6 | 088-L8809___ |
| 271534 Galewood ;1t138.00 272092 Natoma ; B138.00 1 | 143 | 102.5 | 138-L3703xyb-C |
| 272504 Stateline;3b138.00 272506 Stateline;2s138.00 1 | 253 | 107.1 | 170-L0708___ |
| 272506 Stateline;2s138.00 272726 Washingto;B138.00 1 | 253 | 107.0 | 170-L0708___ |
| 342811 5summ Shad T161.00 360334 5summer Shad161.00 1 | 191 | 101.0 | E_L Summer Shade Ekpc-Tva 161 Kv |

**Table 3-16**
**Thermal Overloads in the PJM Area, Winter 2025 Case**

| Monitored Element | Normal or LTE Rating (MVA) | Loading % | Contingency |
|---|---|---|---|
| 204529 27Germantn 115.0 204530 27Germantn 138.00 1 | 157 | 112.1 | Pjm_Ckt5011 |
| 204529 27germantn 115.00 204538 27straban 115.00 1 | 176 | 109.2 | Pjm_Ckt5011 |
| 204538 27straban 115.00 204544 27lincoln 115.00 1 | 179 | 116.6 | Pjm_Ckt5011 |
| 208105 Stee Tr1 230.00 208107 Stee 69.000 1 | 75 | 111.7 | Pl100475 |
| 208106 Stee Tr3 230.00 208107 Stee 69.000 3 | 75 | 129.1 | Pl100475 |
| 232203 Churc_69 69.000 232810 Massyrea 69.000 1 | 64 | 102.6 | Ckt 6773 |
| 235450 01carrol 138.00 235463 01taney 138.00 1 | 143 | 119.0 | Pjm_Ckt5011 |
| 272504 Stateline;3b138.00 272506 Stateline;2s138.00 1 | 253 | 109.2 | 170-L0708___ |
| 272506 Stateline;2s138.00 272726 Washingto; B138.00 1 | 253 | 109.2 | 170-L0708___ |

## Southwest Power Pool

**Table 3-17**
**Thermal Overloads in the SPP Area, Summer 2025 Case**

| Monitored Element | Normal or LTE Rating (MVA) | Loading % | Contingency |
|---|---|---|---|
| 505508 Dardane5 161.00 505514 Clarksv5 161.00 1 | 192 | 104.0 | Loss of 515305 [Ftsmith8 500.00] - 337909 [8ano% 500.00] Ckt 1 |
| 506948 Siloam 5 161.00 512643 Silmcty5 161.00 1 | 317 | 102.7 | Loss of 506935 [Flintcr7 345.00] - 512750 [Tonece7 345.0] Ckt 1 |

| Monitored Element | Normal or LTE Rating (MVA) | Loading % | Contingency |
|---|---|---|---|
| 510948 Earlsboro 4138.00 515055 Maud 4 138.00 1 | 98 | 103.6 | Loss of 515422 [C-River7 345.00] - 510946 [C-River4 138.00] - 510947 [C-River1 13.800] Ckt 1 |
| 515044 Seminol4 138.00 515055 Maud 4 138.00 1 | 287 | 107.3 | Loss of 515045 [Seminol7 345.00] - 515044 [Seminol4 138.00] - 515757 [Semino21 14.400] Ckt 1 |
| 515044 Seminol4 138.00 515178 Parkln 4 138.00 1 | 331 | 109.1 | Loss of 510907 [Pittsb-7 345.00] - 514809 [Johnco 7 345.00] Ckt 1 |
| 522870 Lp-Holly 6230.00 526337 Jones 6230.00 1 | 426 | 115.1 | Loss of 522861 [Lp-Southest6230.00] - 522870 [Lp-Holly 6230] Ckt 1 |
| 524007 Rollhills 3115.00 524106 Northwest 3115.00 1 | 120 | 104.9 | Base case |
| 524623 Deafsmith 6230.00 3wndtr Like Potter Wnd 1 1 | 250 | 104.1 | Loss of 524623 [Deafsmith 6230.00] - 524622 [Deafsmith 3115.00] - 524621 [Defsmth_Tr2113.800] Ckt 2 |
| 525192 Kress_Int 3115.00 3wndtr Enrco 136155 Wnd 1 1 | 84 | 112.4 | Base case |
| 525830 Tuco_Int 6230.00 3wndtr Ge M102345 Wnd 1 1 | 252 | 100.8 | Loss of 525830 [Tuco_Int 6230.00] - 525828 [Tuco_Int 3115.00] - 525819 [Tuco_Tr3 113.200] Ckt 2 |
| 526160 Carlisle 3115.00 3wndtr Wh Xhs70711 Wnd 2 1 | 168 | 105.7 | Loss of 526525 [Wolfforth 6230.00] - 526524 [Wolfforth 3115.00] - 526522 [Wolfrth_Tr1113.200] Ckt 1 |
| 526161 Carlisle 6230.00 3wndtr Wh Xhs70711 Wnd 1 1 | 168 | 110.9 | Loss of 526525 [Wolfforth 6230.00] - 526524 [Wolfforth 3115.00] - 526522 [Wolfrth_Tr1113.200] Ckt 1 |
| 526213 Allen 3115.00 526268 Lubbck_Sth 3115.00 1 | 160 | 116.3 | Loss of 526161 [Carlisle 6230.00] - 526160 [Carlisle 3115.00] - 526157 [Crlsle_Tr1 113.200] Ckt 1 |
| 526268 Lubbck_Sth 3115.0 526602 Sp-Woodrow 3115.0 1 | 154 | 100.5 | Loss of 526677 [Grassland 6230.00] - 526676 [Grassland 3115.00] - 526674 [Graslnd_Tr1113.200] Ckt 1 |
| 526269 Lubbck_Sth 6230.00 526525 Wolfforth 6230.00 1 | 351 | 105.8 | Loss of 522823 [Lp-Milwakee6230] - 522861 [Lp-Southest6230] Ckt 1 |
| 526435 Sundown 6230.0 3wndtr Wh Xds70381 Wnd 1 1 | 187 | 101.5 | Loss of 526435 [Sundown 6230] - 526460 [Amoco_Ss 6230] Ckt 1 |
| 526524 Wolfforth 3115.00 3wndtr Wh 7001668 Wnd 2 1 | 154 | 114.8 | Loss of 526161 [Carlisle 6230.00] - 526160 [Carlisle 3115.00] - 526157 [Crlsle_Tr1 113.200] Ckt 1 |

| Monitored Element | Normal or LTE Rating (MVA) | Loading % | Contingency |
|---|---|---|---|
| 526525 Wolfforth 6230.00 3wndtr Wh 7001668 Wnd 1 1 | 154 | 120.8 | Loss of 526161 [Carlisle 6230.00] - 526160 [Carlisle 3115.00] - 526157 [Crlsle_Tr1 113.200] Ckt 1 |
| 527864 Cunninham 3115 528568 Monumnt_Tp 3115.0 1 | 160 | 111.1 | Loss of 528027 [Rdrunner 7345.00] - 528025 [Rdrunner 3115.00] - 528023 [Rdrnner_Tr1113.200] Ckt 1 |
| 527953 Livstnridge3115.0 528035 Imc_#1_Tp 3115.0 1 | 160 | 143.2 | Loss of 528027 [Rdrunner 7345.00] - 528025 [Rdrunner 3115.00] - 528023 [Rdrnner_Tr1113.200] Ckt 1 |
| 527962 Potash_Jct 3115.0 527999 Intrepdw_Tp3115.0 1 | 160 | 189.1 | Loss of 528027 [Rdrunner 7345.00] - 528025 [Rdrunner 3115.00] - 528023 [Rdrnner_Tr1113.200] Ckt 1 |
| 527999 Intrepdw_Tp3115.0 528035 Imc_#1_Tp 3115.0 1 | 160 | 170.3 | Loss of 528027 [Rdrunner 7345.00] - 528025 [Rdrunner 3115.00] - 528023 [Rdrnner_Tr1113.200] Ckt 1 |
| 528355 Maddox 3115.00 528491 Monument 3115.00 1 | 141 | 102.2 | Loss of 527894 [Hobbs_Int 6230.0] - 528604 [Andrews 6230.0] Ckt 1 |
| 528568 Monumnt_Tp 3115.00 528582 Byrd 3115.00 1 | 141 | 115.8 | Loss of 528027 [Rdrunner 7345.00] - 528025 [Rdrunner 3115.00] - 528023 [Rdrnner_Tr1113.200] Ckt 1 |
| 528596 Cardinal 3115.00 528605 Targa 3115.00 1 | 120 | 163.8 | Loss of 528027 [Rdrunner 7345.00] - 528025 [Rdrunner 3115.00] - 528023 [Rdrnner_Tr1113.200] Ckt 1 |
| 528603 Na_Enrich 3115.00 528605 Targa 3115.00 1 | 120 | 193.1 | Loss of 528027 [Rdrunner 7345.00] - 528025 [Rdrunner 3115.00] - 528023 [Rdrnner_Tr1113.200] Ckt 1 |
| 531445 Grdncty3 115.00 531480 Ksavwtp3 115.00 1 | 119.5 | 120.5 | Loss of 531449 [Holcomb7 345.00] - 531448 [Holcomb3 115.00] - 531450 [Holcter1 13.800] Ckt 1 |
| 539684 Otissub3 115.00 3wndtr Otissub3 Wnd 2 1 | 7.5 | 127.7 | Base case |
| 539694 Spearvl3 115.00 3wndtr Spearvl3 Wnd 2 1 | 7.5 | 116.4 | Base case |
| 640131 Colmb.W4 230.0 3wndtr Colmb.Wst T1 Wnd 2 1 | 56 | 104.6 | Loss of 640131 [Colmb.W4 230.00] - 640132 [Colmb.W9 34.500] - 643040 [Colmb.Wstt2913.800] Ckt 2 |
| 640131 Colmb.W4 230.0 3wndtr Colmb.Wst T2 Wnd 2 2 | 56 | 104.1 | Loss of 640131 [Colmb.W4 230.00] - 640132 [Colmb.W9 34.500] - 643039 [Colmb.Wstt1913.800] Ckt 1 |
| 640305 Oneill 7 115.00 640349 Spencer7 115.00 1 | 120 | 102.4 | Loss of 640226 [Hoskins3 345.0] - 640520 [Neligh.East3345.0] Ckt 1 |

| Monitored Element | Normal or LTE Rating (MVA) | Loading % | Contingency |
|---|---|---|---|
| 640349 Spencer7 115.00 652510 Ftrandl7 115.00 1 | 120.7 | 110.9 | Loss of 640226 [Hoskins3 345.0] - 640520 [Neligh.East3345.0] Ckt 1 |
| 646221 S1221 5 161.00 646255 S1255 5 161.00 1 | 352 | 101.3 | Loss of 645459 [S3459 3 345.00] - 646209 [S1209 5 161.00] - 648259 [S3459t39 13.800] Ckt 1 |

**Table 3-18**
**Thermal Overloads in the SPP Area, Winter 2025 Case**

| Monitored Element | Normal or LTE Rating (MVA) | Loading % | Contingency |
|---|---|---|---|
| 527864 Cunninham 3115.0 528568 Monumnt_Tp 3115 1 | 177 | 108.5 | Loss of 527965 [Kiowa 7345.00] - 528027 [Rdrunner 7345.00] Ckt 1 |
| 527953 Livstnridge3115.00 528035 Imc_#1_Tp 3115.00 1 | 177 | 144.5 | Loss of 528027 [Rdrunner 7345.00] - 528025 [Rdrunner 3115.00] - 528023 [Rdrnner_Tr1113.200] Ckt 1 |
| 527962 Potash_Jct 3115.00 527999 Intrepdw_Tp3115.00 1 | 177 | 179.3 | Loss of 527965 [Kiowa 7345.00] - 528027 [Rdrunner 7345.00] Ckt 1 |
| 527999 Intrepdw_Tp3115.0 528035 Imc_#1_Tp 3115.0 1 | 177 | 164.9 | Loss of 527965 [Kiowa 7345.00] - 528027 [Rdrunner 7345.00] Ckt 1 |
| 528554 Cooper_Rnch3115.00 528582 Byrd 3115.00 1 | 156 | 102.2 | Loss of 527965 [Kiowa 7345.00] - 528027 [Rdrunner 7345.00] Ckt 1 |
| 528568 Monumnt_Tp 3115.00 528582 Byrd 3115.00 1 | 156 | 116.1 | Loss of 527965 [Kiowa 7345.00] - 528027 [Rdrunner 7345.00] Ckt 1 |
| 528596 Cardinal 3115.00 528605 Targa 3115.00 1 | 139 | 144.2 | Loss of 527965 [Kiowa 7345.00] - 528027 [Rdrunner 7345.00] Ckt 1 |
| 528603 Na_Enrich 3115.00 528605 Targa 3115.00 1 | 139 | 163.3 | Loss of 527965 [Kiowa 7345.00] - 528027 [Rdrunner 7345.00] Ckt 1 |
| 640131 Colmb.W4 230 3wndtr Colmb.Wst T1 Wnd 2 1 | 56 | 104.1 | Loss of 640131 [Colmb.W4 230.00] - 640132 [Colmb.W9 34.500] - 643040 [Colmb.Wstt2913.800] Ckt 2 |

## SERC

**Table 3-19**
**Pre Upgrades—Thermal Overloads in the SERC Area, Summer 2025 Case**

| Monitored Element | Normal or LTE Rating (MVA) | Loading % | Contingency |
|---|---|---|---|
| 304389 6fayeast230t230.00 304369 2fayeast69tt69.000 2 | 200 | 110.6 | Loss of 304389 [6fayeast230t230.00] - 304369 [2fayeast69tt69.000] Ckt 3 |
| 304389 6fayeast230t230.00 304369 2fayeast69tt69.000 3 | 200 | 110.6 | Loss of 304389 [6fayeast230t230.00] - 304369 [2fayeast69tt69.000] Ckt 2 |
| 306058 6sadlery 230.00 309458 1sadle 4 1.0000 4 | 400 | 104.4 | Loss of 306718 [6sadlerr 230.00] - 306826 [6ernest2 230.00] Ckt 1 |
| 306545 6woodlwn 230.00 309472 1woodl 5 1.0000 5 | 418 | 100.1 | Loss of 306545 [6woodlwn 230.00] - 309473 [1woodl 6 1.0000] Ckt 6 |
| 306600 Harrisbg 100.00 308575 Uncc100t 100.00 1 | 120 | 100.1 | Base case |
| 306713 6beckrdt 230.00 309507 Beck3 100.00 3 | 261 | 100.1 | Loss of 306713 [6beckrdt 230.00] - 309505 [Beck1 100.00] Ckt 1 |
| 306897 Glen Rvn 100.00 309061 Glen Cap 100.00 Z1 | 124 | 100.4 | Base case |
| 309545 Woodl5 100.00 309472 1woodl 5 1.0000 5 | 399 | 101.2 | Loss of 306545 [6woodlwn 230.00] - 309473 [1woodl 6 1.0] Ckt 6 |
| 311134 3purrysb 115.00 312721 6purrysb 230.00 1 | 120 | 128.9 | Loss of 312705 [6blufftn 230.00] - 312721 [6purrysb 230.0] Ckt 1 |
| 317246 3elsnrsw3 115.00 317264 6elsnrsw6 230.00 1 | 150 | 102.5 | Base case |
| 339003 High Rck 100.00 339005 Tuckertn 100.00 1 | 103 | 108.9 | Loss of 306836 [8woodlf 500.0] - 309057 [8godbeyrtrt 500.0] Ckt 1 |
| 339150 3jst-Sc 115.00 370365 3clarkhill 115.00 1 | 152.9 | 111.3 | Loss of 371308 [6srs2 230.00] - 380115 [6vogtle 230.00] Ckt 1 |
| 360028 5mem Junct 161.00 361034 5s Bowlgrn T161.00 1 | 227.5 | 110.1 | Loss of 360439 [5portland Ss161.00] - 361570 [5mitchvle Tp161.00] Ckt 1 |
| 360061 5madison #1 161.00 360294 5huntsvl Al 161.00 1 | 289.5 | 108.1 | Loss of 360281 [5limestone 161.00] - 361637 [5cty Line Rd161.00] Ckt 1 |
| 360096 5alcoa Sw Tn161.00 361254 5profit Spgs161.00 1 | 472.1 | 100.6 | Loss of 360093 [8bull Run Fp500.00] - 360097 [8volunteer 500.00] Ckt 1 |

| Monitored Element | Normal or LTE Rating (MVA) | Loading % | Contingency |
|---|---|---|---|
| 360152 5s Jackson 161.00 361704 5flex Tn 161.00 1 | 226.7 | 137.6 | Loss of 360019 [8jackson Tn 500.00] - 360683 [5jackson B#2161.00] - 362579 [1jackson Tn 13.200] Ckt 1 |
| 360241 5dekalb Ms 161.00 360370 5shuqualak 161.00 1 | 298.7 | 101.1 | Loss of 360241 [5dekalb Ms 161.00] - 361671 [5clevland Ms161.00] Ckt 1 |
| 360241 5dekalb Ms 161.00 361671 5clevland Ms161.00 1 | 299.2 | 100.4 | Loss of 360241 [5dekalb Ms 161.00] - 360370 [5shuqualak 161.00] Ckt 1 |
| 360331 5bowling Grn161.00 361034 5s Bowlgrn T161.00 1 | 227.5 | 110.0 | Loss of 360439 [5portland Ss161.00] - 361570 [5mitchvle Tp161.00] Ckt 1 |
| 360334 5summer Shad161.00 342811 5summ Shad T161.00 1 | 191 | 101.0 | Loss of 360334 [5summer Shad161.00] - 342814 [5summ Shade 161.00] Ckt 1 |
| 360466 5cherokee Hp161.00 3wndtr Wnd 1 2 | 66.1 | 115.9 | Base case |
| 360547 5gallatin F2161.00 360570 5cairo Bend 161.00 1 | 371.4 | 102.7 | Loss of 360351 [5gallatn Pri161.00] - 360547 [5gallatin F2161.00] Ckt 1 |
| 360678 5shelby Mem1161.00 365573 5bol Huse 75161.00 1 | 334.1 | 110.2 | Loss of 360025 [8cordova Tn 500.00] - 360026 [5cordova #1 161.00] - 362317 [1cordova #1 13.200] Ckt 1 |
| 360724 5freeport #1161.00 365579 5oakville 44161.0 1 | 223.1 | 113.4 | Loss of 360024 [5freeport Tn161.00] - 360725 [5freeport #2161.00] Ckt Z1 |
| 360724 5freeport #1161.0 365935 5shelby Dr74161.0 1 | 223.1 | 114.9 | |
| 370330 3stev Ck 115.00 370335 3clkhl T 115.00 1 | 138.6 | 102.7 | Loss of 371308 [6srs2 230.00] - 380115 [6vogtle 230.00] Ckt 1 |
| 370364 3salemss 115.00 370457 3baldock 115.00 1 | 110.5 | 118.7 | Loss of 380008 [8vogtle 500.0] - 380009 [8w Mcintosh 500.0] Ckt 1 |
| 370457 3baldock 115.00 370458 3allen T 115.00 1 | 110.5 | 114.5 | Loss of 380008 [8vogtle 500.0] - 380009 [8w Mcintosh 500.0] Ckt 1 |
| 370458 3allen T 115.00 370459 3fairfax 115.00 1 | 110.5 | 103.9 | Loss of 380008 [8vogtle 500.0] - 380009 [8w Mcintosh 500.0] Ckt 1 |
| 380134 6butler 230.00 383407 6paw Paw Slr230.00 1 | 30 | 100.0 | Base case |
| 380638 3butler 115.00 383408 3strata Slr 115.00 1 | 20 | 100.0 | Base case |
| 381010 3bemiss 115.00 382549 3pine Grv B2115.00 1 | 91 | 103.6 | Loss of 381885 [6w Valdosta 230.00] - 381886 [3w Valdosta 115.00] Ckt 1 |

| Monitored Element | Normal or LTE Rating (MVA) | Loading % | Contingency |
|---|---|---|---|
| 381114 3ft Benn 2 115.00 383411 3benning Slr115.00 1 | 30 | 100.0 | Base case |
| 389001 6mcintosh 230.00 389021 3mcintosh 115.00 1 | 400 | 105.8 | Loss of 389001 [6mcintosh 230.0] - 389176 [6crossgate 230.0] Ckt 1 |

**Table 3-20**
**Post Upgrades—Thermal Overloads in the SERC Area, Summer 2025 Case**

| Monitored Element | Normal or LTE Rating (MVA) | Loading % | Contingency |
|---|---|---|---|
| 304389 6fayeast230t230.00 304369 2fayeast69tt69.00 2 | 200 | 110.6 | Loss of 304389 [6fayeast230t230.0] - 304369 [2fayeast69tt69] Ckt 3 |
| 304389 6fayeast230t230.00 304369 2fayeast69tt69.00 3 | 200 | 110.6 | Loss of 304389 [6fayeast230t230.0] - 304369 [2fayeast69tt69] Ckt 2 |
| 306058 6sadlery 230.00 309458 1sadle 4 1.0000 4 | 400 | 104.4 | Loss of 306718 [6sadlerr 230.00] - 309464 [1sadle 3 1.00] Ckt 3 |
| 306545 6woodlwn 230.00 309472 1woodl 5 1.0000 5 | 418 | 100.1 | Loss of 306545 [6woodlwn 230.00] - 309473 [1woodl 6 1.0] Ckt 6 |
| 306600 Harrisbg 100.00 308575 Uncc100t 100.00 1 | 120 | 100.1 | Base case |
| 306713 6beckrdt 230.00 309507 Beck3 100.00 3 | 261 | 100.1 | Loss of 306713 [6beckrdt 230.00] - 309505 [Beck1 100.00] Ckt 1 |
| 306897 Glen Rvn 100.00 309061 Glen Cap 100.00 Z1 | 124 | 100.4 | Base case |
| 309545 Woodl5 100.00 309472 1woodl 5 1.0000 5 | 399 | 101.2 | Loss of 306545 [6woodlwn 230.00] - 309473 [1woodl 6 1.0] Ckt 6 |
| 311134 3purrysb 115.00 312721 6purrysb 230.00 1 | 120 | 128.9 | Loss of 312705 [6blufftn 230.00] - 312721 [6purrysb 230.0] Ckt 1 |
| 339003 High Rck 100.00 339005 Tuckertn 100.00 1 | 103 | 108.9 | Loss of 306836 [8woodlf 500.00] - 309057 [8godbeyrtrt 500.00] Ckt 1 |
| 339150 3jst-Sc 115.00 370365 3clarkhill 115.00 1 | 152.9 | 111.3 | Loss of 371308 [6srs2 230.00] - 380115 [6vogtle 230.00] Ckt 1 |

| Monitored Element | Normal or LTE Rating (MVA) | Loading % | Contingency |
|---|---|---|---|
| 360028 5mem Junct 161.00 361034 5s Bowlgrn T161.00 1 | 227.5 | 110.1 | Loss of 360439 [5portland Ss161.00] - 361570 [5mitchvle Tp161.00] Ckt 1 |
| 360061 5madison #1 161.00 360294 5huntsvl Al 161.00 1 | 289.5 | 108.1 | Loss of 360281 [5limestone 161.00] - 361637 [5cty Line Rd161.00] Ckt 1 |
| 360096 5alcoa Sw Tn161.00 361254 5profit Spgs161.00 1 | 472.1 | 100.6 | Loss of 360093 [8bull Run Fp500.00] - 360097 [8volunteer 500.00] Ckt 1 |
| 360152 5s Jackson 161.00 361704 5flex Tn 161.00 1 | 226.7 | 137.6 | Loss of 360019 [8jackson Tn 500.00] - 360683 [5jackson B#2161.00] - 362579 [1jackson Tn 13.200] Ckt 1 |
| 360241 5dekalb Ms 161.00 360370 5shuqualak 161.00 1 | 298.7 | 101.1 | Loss of 360241 [5dekalb Ms 161.00] - 361671 [5clevland Ms161.00] Ckt 1 |
| 360241 5dekalb Ms 161.00 361671 5clevland Ms161.00 1 | 299.2 | 100.4 | Loss of 360241 [5dekalb Ms 161.00] - 360370 [5shuqualak 161.00] Ckt 1 |
| 360331 5bowling Grn161.00 361034 5s Bowlgrn T161.00 1 | 227.5 | 110.0 | Loss of 360439 [5portland Ss161.00] - 361570 [5mitchvle Tp161.00] Ckt 1 |
| 360334 5summer Shad161.00 342811 5summ Shad T161.00 1 | 191 | 101.0 | Loss of 360334 [5summer Shad161.00] - 342814 [5summ Shade 161.00] Ckt 1 |
| 360466 5cherokee Hp161.00 3wndtr Wnd 1 2 | 66.1 | 115.9 | Base case |
| 360547 5gallatin F2161.0 360570 5cairo Bend 161.00 1 | 371.4 | 102.7 | Loss of 360351 [5gallatn Pri161] - 360547 [5gallatin F2161] Ckt 1 |
| 360678 5shelby Mem1161.00 365573 5bol Huse 75161.00 1 | 334.1 | 110.2 | Loss of 360025 [8cordova Tn 500.00] - 360026 [5cordova #1 161.00] - 362317 [1cordova #1 13.200] Ckt 1 |
| 360724 5freeport #1161.0 365579 5oakville 44161.00 1 | 223.1 | 113.4 | Loss of 360024 [5freeport Tn161.00] - 360725 [5freeport #2161.00] Ckt Z1 |
| 360724 5freeport #1161.0 365935 5shelby Dr74161.0 1 | 223.1 | 114.9 | |
| 370330 3stev Ck 115.00 370335 3clkhl T 115.00 1 | 138.6 | 102.7 | Loss of 371308 [6srs2 230.00] - 380115 [6vogtle 230.00] Ckt 1 |
| 370364 3salemss 115.00 370457 3baldock 115.00 1 | 110.5 | 118.7 | Loss of 380008 [8vogtle 500] - 380009 [8w Mcintosh 500] Ckt 1 |
| 370457 3baldock 115.00 370458 3allen T 115.00 1 | 110.5 | 114.5 | Loss of 380008 [8vogtle 500] - 380009 [8w Mcintosh 500] Ckt 1 |
| 370458 3allen T 115.00 370459 3fairfax 115.00 1 | 110.5 | 103.9 | Loss of 380008 [8vogtle 500] - 380009 [8w Mcintosh 500] Ckt 1 |

| Monitored Element | Normal or LTE Rating (MVA) | Loading % | Contingency |
|---|---|---|---|
| 380134 6butler 230.00 383407 6paw Paw Slr230.00 1 | 30 | 100.0 | Base case |
| 380638 3butler 115.00 383408 3strata Slr 115.00 1 | 20 | 100.0 | Base case |
| 381114 3ft Benn 2 115.00 383411 3benning Slr115.00 1 | 30 | 100.0 | Base case |
| 389001 6mcintosh 230.00 389021 3mcintosh 115.00 1 | 400 | 105.8 | Loss of 389001 [6mcintosh 230] - 389176 [6crossgate 230] Ckt 1 |

**Table 3-21**
**Pre Upgrades—Thermal Overloads in the SERC Area, Winter 2025 Case**

| Monitored Element | Normal or LTE Rating (MVA) | Loading % | Contingency |
|---|---|---|---|
| 306108 6pisgah 230.00 309450 1pisga 1 1.0000 1 | 213 | 109.7 | Loss of 306108 [6pisgah 230.00] - 309451 [1pisga 2 1.0000] Ckt 2 |
| 306108 6pisgah 230.00 309451 1pisga 2 1.0000 2 | 220 | 107.0 | Loss of 306108 [6pisgah 230.00] - 309450 [1pisga 1 1.0000] Ckt 1 |
| 306135 Daniel 100.00 306220 Blrec25 100.00 1 | 127 | 100.9 | Loss of 306108 [6pisgah 230.00] - 306110 [6shiloh 230.00] Ckt 1 |
| 309363 Pinnacl2 100.00 308336 1pinacle 44.000 1 | 23.6 | 107.4 | Base case |
| 309363 Pinnacl2 100.00 308336 1pinacle 44.000 2 | 22.2 | 114.8 | Base case |
| 309513 Pisg1 100.00 309450 1pisga 1 1.0000 1 | 220 | 105.6 | Loss of 306108 [6pisgah 230.00] - 309451 [1pisga 2 1.0000] Ckt 2 |
| 311134 3purrysb 115.00 312721 6purrysb 230.00 1 | 120 | 104.6 | Loss of 312705 [6blufftn 230.00] - 312721 [6purrysb 230.00] Ckt 1 |
| 311289 3forsbk 115.00 312820 3pine I 115.00 1 | 202 | 102.7 | Loss of 311716 [6bucksvl 230.00] - 311717 [3bucksvl 115.0] Ckt 1 |
| 311716 6bucksvl 230.00 311717 3bucksvl 115.00 1 | 250 | 103.5 | Base case |

Eastern Interconnection Planning Collaborative

| Monitored Element | Normal or LTE Rating (MVA) | Loading % | Contingency |
|---|---|---|---|
| 312819 3perry R 115.00 312820 3pine I 115.00 1 | 202 | 113.7 | Loss of 311716 [6bucksvl 230.0] - 311717 [3bucksvl 115.0] Ckt 1 |
| 311323 3campfld 115.00 312776 3greenf 115.00 1 | 275 | 109.5 | Loss of 311716 [6bucksvl 230.00] - 312719 [6winyah 230.0] Ckt 1 |
| 311609 3ngrnfdt 115.00 312776 3greenf 115.00 1 | 239 | 126.6 | |
| 311716 6bucksvl 230.00 312717 6perry R 230.00 1 | 586 | 112.6 | Loss of 311716 [6bucksvl 230.00] - 312717 [6perry R 230.0] Ckt 2 |
| 339003 High Rck 100.00 339005 Tuckertn 100.00 1 | 103 | 104.8 | Loss of 306836 [8woodlf 500] - 309057 [8godbeyrtrt 500] Ckt 1 |
| 360152 5s Jackson 161.00 361704 5flex Tn 161.00 1 | 310.9 | 104.7 | Loss of 360019 [8jackson Tn 500.00] - 360683 [5jackson B#2161.00] - 362579 [1jackson Tn 13.200] Ckt 1 |
| 360236 5columbus Ms161.00 361052 5weyerhsr Tp161.00 1 | 334.6 | 100.2 | Loss of 360241 [5dekalb Ms 161.00] - 361671 [5clevland Ms161.00] Ckt 1 |
| 360344 5wcookevl Tn161.00 361372 5s Cookevlle161.00 1 | 209.4 | 108.4 | Loss of 360347 [5cordell Hp 161] - 360506 [5baxter Tn 161] Ckt 1 |
| 360466 5cherokee Hp161.00 3wndtr Wnd 1 2 | 66.1 | 116.3 | Base case |
| 361333 5kyles Ford 161.00 362771 2kyles Ford 69.00 1 | 33.3 | 122.7 | Loss of 361333 [5kyles Ford 161.0] - 362771 [2kyles Ford 69] Ckt 1 |
| 361333 5kyles Ford 161.00 362771 2kyles Ford 69.00 2 | 33.3 | 122.7 | Loss of 361333 [5kyles Ford 161.0] - 362771 [2kyles Ford 69] Ckt 1 |
| 370364 3salemss 115.00 370457 3baldock 115.00 1 | 110.5 | 119.0 | Loss of 380008 [8vogtle 500] - 380009 [8w Mcintosh 500] Ckt 1 |
| 370457 3baldock 115.00 370458 3allen T 115.00 1 | 110.5 | 115.8 | Loss of 380008 [8vogtle 500] - 380009 [8w Mcintosh 500] Ckt 1 |
| 370458 3allen T 115.00 370459 3fairfax 115.00 1 | 110.5 | 105.1 | Loss of 380008 [8vogtle 500] - 380009 [8w Mcintosh 500] Ckt 1 |
| 380804 3bonaire B1 115.00 382343 6bonaire B1 230 1 | 400 | 102.0 | Loss of 382344 [6bonaire B2 230] - 382351 [3bonaire B2 115] Ckt 1 |
| 381010 3bemiss 115.00 382549 3pine Grv B2115.00 1 | 101 | 106.0 | Loss of 381885 [6w Valdosta 230.00] - 381886 [3w Valdosta 115.00] Ckt 1 |
| 382344 6bonaire B2 230.0 382351 3bonaire B2 115.0 1 | 400 | 102.0 | Loss of 382343 [6bonaire B1 230] - 380804 [3bonaire B1 115] Ckt 1 |
| 389001 6mcintosh 230.00 389021 3mcintosh 115.00 1 | 400 | 111.8 | Loss of 389044 [6meldrim 230.00] - 389029 [3meldrim115.0] Ckt 1 |

**Table 3-22**
**Post Upgrades—Thermal Overloads in the SERC Area, Winter 2025 Case**

| Monitored Element | Normal or LTE Rating (MVA) | Loading % | Contingency |
|---|---|---|---|
| 306108 6pisgah 230.00 309450 1pisga 1 1.0000 1 | 213 | 109.7 | Loss of 306108 [6pisgah 230.00] - 309451 [1pisga 2 1.0000] Ckt 2 |
| 306108 6pisgah 230.00 309451 1pisga 2 1.0000 2 | 220 | 107 | Loss of 306108 [6pisgah 230.00] - 309450 [1pisga 1 1.0000] Ckt 1 |
| 306135 Daniel 100.00 306220 Blrec25 100.00 1 | 127 | 100.8 | Loss of 306108 [6pisgah 230.00] - 306110 [6shiloh 230.00] Ckt 1 |
| 309363 Pinnacl2 100.00 308336 1pinacle 44.000 1 | 23.6 | 107.4 | Base case |
| 309363 Pinnacl2 100.00 308336 1pinacle 44.000 2 | 22.2 | 114.8 | Base case |
| 309513 Pisg1 100.00 309450 1pisga 1 1.0000 1 | 220 | 105.6 | Loss of 306108 [6pisgah 230.00] - 309451 [1pisga 2 1.0000] Ckt 2 |
| 311134 3purrysb 115.00 312721 6purrysb 230.00 1 | 120 | 104.6 | Loss of 312705 [6blufftn 230.00] - 312721 [6purrysb 230.00] Ckt 1 |
| 339003 High Rck 100.00 339005 Tuckertn 100.00 1 | 103 | 104.9 | Loss of 306836 [8woodlf 500.00] - 309057 [8godbeyrtrt 500] Ckt 1 |
| 360152 5s Jackson 161.00 361704 5flex Tn 161.00 1 | 310.9 | 104.7 | Loss of 360019 [8jackson Tn 500.00] - 360683 [5jackson B#2161.00] - 362579 [1jackson Tn 13.200] Ckt 1 |
| 360236 5columbus Ms161.00 361052 5weyerhsr Tp161.00 1 | 334.6 | 100.2 | Loss of 360241 [5dekalb Ms 161.00] - 361671 [5clevland Ms161.00] Ckt 1 |
| 360344 5wcookevl Tn161.00 361372 5s Cookevlle161.00 1 | 209.4 | 108.4 | Loss of 360347 [5cordell Hp 161.00] - 360506 [5baxter Tn 161.00] Ckt 1 |
| 360466 5cherokee Hp161.00 3wndtr Wnd 1 2 | 66.1 | 116.3 | Base case |
| 361333 5kyles Ford 161.00 362771 2kyles Ford 69.00 1 | 33.3 | 122.7 | Loss of 361333 [5kyles Ford 161] - 362771 [2kyles Ford 69.0] Ckt 2 |
| 361333 5kyles Ford 161.00 362771 2kyles Ford 69.00 2 | 33.3 | 122.7 | Loss of 361333 [5kyles Ford 161] - 362771 [2kyles Ford 69.0] Ckt 1 |
| 370364 3salemss 115.00 370457 3baldock 115.00 1 | 110.5 | 118.8 | Loss of 380008 [8vogtle 500] - 380009 [8w Mcintosh 500] Ckt 1 |
| 370457 3baldock 115.00 370458 3allen T 115.00 1 | 110.5 | 115.6 | Loss of 380008 [8vogtle 500] - 380009 [8w Mcintosh 500] Ckt 1 |

| Monitored Element | Normal or LTE Rating (MVA) | Loading % | Contingency |
|---|---|---|---|
| 370458 3allen T 115.00 370459 3fairfax 115.00 1 | 110.5 | 104.9 | Loss of 380008 [8vogtle 500] - 380009 [8w Mcintosh 500] Ckt 1 |
| 380804 3bonaire B1 115.00 382343 6bonaire B1 230.00 1 | 400 | 102.0 | Loss of 382344 [6bonaire B2 230.00] - 382351 [3bonaire B2 115.00] Ckt 1 |
| 382344 6bonaire B2 230.00 382351 3bonaire B2 115.00 1 | 400 | 102.0 | Loss of 382343 [6bonaire B1 230.00] - 380804 [3bonaire B1 115.00] Ckt 1 |
| 389001 6mcintosh 230.00 389021 3mcintosh 115.00 1 | 400 | 111.8 | Loss of 389044 [6meldrim 230.00] - 389029 [3meldrim 115] Ckt 1 |

## FRCC

**Table 3-23**
**Thermal Overloads in FRCC Area, Summer 2025 Case**

| Monitored Element | Normal or LTE Rating (MVA) | Loading % | Contingency |
|---|---|---|---|
| 400005 Flacity 230.0 400732 Mcgregor 230.0 1 | 596 | 104.6 | Loss of 401014 [Princeton 230.0] - 401603 [Tp North 230.0] Ckt 1 |
| 400036 Dade 138.0 400643 Dade Sub 138.0 1 | 222 | 107.0 | Loss of 400109 [Levee 230.0] - 400115 [Milam 230.0] Ckt 1 |
| 400038 Davis 138.0 400105 Davis 230.0 1 | 637 | 103.4 | Loss of 400105 [Davis 230.0] - 400038 [Davis 138.0] Ckt 2 |
| 400038 Davis 138.0 400657 Court 138.0 1 | 287 | 110.0 | Loss of 400839 [Galtap 230.0] - 400945 [Galloway 230.0] Ckt 1 |
| 400101 Weston V 138.0 400776 Cntylitp 138.0 1 | 287 | 113.9 | Loss of 400156 [Moffett 230.0] - 400182 [Laudania 230.0] Ckt 1 |
| 400109 Levee 230.0 400115 Milam 230.0 1 | 637 | 102.2 | Loss of 400175 [Andytown 230] - 400520 [Crossbow 230.0] Ckt 1 |
| 400119 Turkey P 230.0 400732 Mcgregor 230.0 1 | 596 | 106.0 | Loss of 401014 [Princeton 230.0] - 401603 [Tp North 230.0] Ckt 1 |
| 400126 Hollywtp 138.0 400147 Halndale 138.0 1 | 222 | 112.4 | Loss of 400156 [Moffett 230.0] - 400182 [Laudania 230.0] Ckt 1 |

| Monitored Element | Normal or LTE Rating (MVA) | Loading % | Contingency |
|---|---|---|---|
| 400190 Clintmre 230.0 400983 Marymnt 230.0 1 | 514 | 102.4 | Loss of 400176 [Broward 230.0] - 400986 [Yamattap 230.0] Ckt 1 |
| 400273 Yamato 230.0 400983 Marymnt 230.0 1 | 514 | 107.0 | Loss of 400176 [Broward 230.0] - 400986 [Yamattap 230.0] Ckt 1 |
| 400330 Ringling 138.0 400336 Tuttle 138.0 1 | 316 | 103.2 | Loss of 400308 [Frtville 230.0] - 400352 [Ringling 230.0] Ckt 1 |
| 400392 Frontnac 115.0 400572 Mcdonell 115.0 1 | 145 | 118.3 | Loss of 400461 [Cape K 230.0] - 400494 [Tulsa 230.0] Ckt 1 |
| 400424 St Aug 115.0 400946 Kacie 115.0 1 | 120 | 103.5 | Loss of 400841 [Millcrek 230.0] - 400840 [Millcrek 115.0] Ckt 1 |
| 400461 Cape K 230.0 401117 Cape-Cl2 230.0 1 | 1,175 | 105.6 | Base case |
| 400524 Laudrdlo 138.0 400777 Bevertp2 138.0 1 | 344 | 121.1 | Loss of 400156 [Moffett 230.0] - 400182 [Laudania 230.0] Ckt 1 |
| 400559 Franklin 138.0 401008 Coast 138.0 1 | 222 | 100.7 | Loss of 400552 [Auburn 230.0] - 401135 [Lrlwdisttp 230.0] Ckt 1 |
| 400871 Tavrnier 138.0 400879 Islmrdascap 138.0 1 | 243 | 100.6 | Loss of 400005 [Flacity 230.0] - 400732 [Mcgregor 230.0] Ckt 1 |
| 400872 Islmrada 138.0 400877 Crawlkey 138.0 1 | 221 | 112.5 | Loss of 400005 [Flacity 230.0] - 400732 [Mcgregor 230.0] Ckt 1 |
| 400872 Islmada 138.0 400879 Islmrdascap 138.0 Z1 | 243 | 108.9 | Loss of 400005 [Flacity 230.0] - 400040 [Fla City 138.0] Ckt 1 |
| 403518 Brookrdge 230 3wndtr Brookridge Wnd 2 1 | 750 | 101.3 | Loss of 403551 [Central Fla 500] - 403558 [Citrus Enrgy500] Ckt 31 |
| 403550 Brookrdge 500 3wndtr Brookridge Wnd 1 1 | 750 | 102.2 | Loss of 403551 [Central Fla 500] - 403558 [Citrus Enrgy500] Ckt 31 |
| 405712 Magn Rch 230.0 405551 Ou Mag R 69.0 1 | 186 | 101.0 | Loss of 402882 [Holopaw 1 230.0] - 407431 [Stc East 230.0] Ckt 1 |
| 408850 Belcrk 230.0 408852 Belcrk 69.0 1 | 239 | 104.9 | Loss of 408860 [So Gib-S 230.0] - 408862 [So Gib-S 69.00] Ckt 1 |

**Table 3-24**
**Thermal Overloads in the FRCC Area, Winter 2025 Case**

| Monitored Element | Normal or LTE Rating (MVA) | Loading % | Contingency |
|---|---|---|---|
| 400298 Cocoplum 138.0 400559 Franklin 138.0 1 | 222 | 101.5 | Loss of 400552 [Auburn 230.0] - 401135 [Lrlwdisttp 230.0] Ckt 1 |
| 400309 Ft Myers 138.0 400595 Ftmyertp 138.0 1 | 353 | 103.8 | Loss of 400351 [Orange R 230.0] - 400541 [Jetport 230.0] Ckt 1 |
| 400353 Whidden 230.0 402890 Vandolah 230.0 1 | 1068 | 105.5 | Loss of 400342 [Charlote 230.0] - 407152 [Seci_Van 230.0] Ckt 1 |
| 400392 Frontnac 115.0 400572 Mcdonell 115.0 1 | 145 | 127.8 | Loss of 400461 [Cape K 230.0] - 400494 [Tulsa 230.0] Ckt 1 |
| 400399 Indian R 115.0 400572 Mcdonell 115.0 1 | 145 | 110.1 | Loss of 400461 [Cape K 230.0] - 400494 [Tulsa 230.0] Ckt 1 |
| 400411 N Riv Tp 115.0 400427 Starke 115.0 1 | 134 | 111.4 | Loss of 400458 [Baldwin 230.0] - 400375 [Baldwin 115.0] Ckt 1 |
| 400460 Brevard 230.0 400461 Cape K 230.0 2 | 514 | 102.2 | Loss of 400460 [Brevard 230.0] - 400461 [Cape K 230.0] Ckt 3 |
| 400460 Brevard 230.0 400461 Cape K 230.0 3 | 514 | 102.3 | Loss of 400460 [Brevard 230.0] - 400461 [Cape K 230.0] Ckt 2 |
| 400460 Brevard 230.0 400717 Cox 230.0 1 | 514 | 100.4 | Loss of 400460 [Brevard 230.0] - 400461 [Cape K 230.0] Ckt 3 |
| 400461 Cape K 230.0 400717 Cox 230.0 1 | 514 | 101.9 | Loss of 400460 [Brevard 230.0] - 400461 [Cape K 230.0] Ckt 3 |
| 400461 Cape K 230.0 401117 Cape-Cl2230.0 1 | 1,175 | 137.2 | Loss of 400467 [Poinsett 230.0] - 400476 [Poinsett 500.0] Ckt 1 |
| 400559 Franklin 138.0 401008 Coast 138.0 1 | 222 | 127.6 | Loss of 400552 [Auburn 230.0] - 401135 [Lrlwdisttp 230.0] Ckt 1 |
| 400595 Ftmyertp 138.0 400893 Hanson 138.0 1 | 353 | 101.7 | Loss of 400351 [Orange R 230.0] - 400541 [Jetport 230] Ckt 1 |
| 403518 Brokrdge230.0 3wndtr Brokdge Wnd 2 1 | 750 | 103.7 | Loss of 403551 [Central Fla 500] - 403558 [Citrus Enrgy500.0] Ckt 31 |
| 403550 Brokrdge500.0 3wndtr Brokrdge Wnd 1 1 | 750 | 104.5 | Loss of 403551 [Central Fla 500.0] - 403558 [Citrus Enrgy500.00] Ckt 31 |
| 408010 Dlmbry-W 230.0 408018 Dlmbry-W 69 1 | 242 | 108.6 | Loss of 408400 [Chapman 230.0] - 408402 [Chapman 69.00] Ckt 1 |

| Monitored Element | Normal or LTE Rating (MVA) | Loading % | Contingency |
|---|---|---|---|
| 408610 Fishhawk 230.0 408700 Gannon 230.0 1 | 535.4 | 108.2 | Loss of 408650 [Aspen 230.0] - 408900 [B Bend 230.0] Ckt 1 |
| 408850 Belcrk 230.0 408852 Belcrk 69.0 1 | 239 | 105.4 | Loss of 408860 [So Gib-S 230.0] - 408862 [So Gib-S 69.00] Ckt 1 |
| 409000 Polkplnt 230.0 409020 Mines E 230.0 1 | 617.5 | 116.5 | Loss of 408650 [Aspen 230.0] - 409000 [Polkplnt 230.0] Ckt 1 |
| 409010 Mines W 230 409020 Mines E 230 .Z1 | 637.4 | 107.4 | Loss of 408650 [Aspen 230.0] - 409000 [Polkplnt 230.0] Ckt 1 |

#### 3.3.2 Summary of Voltage Results

A collective voltage analysis was performed on the 2025 summer and winter peak roll-up cases for each individual Planning Authority regions (NPCC, MISO, PJM, SERC, SPP, and FRCC). Several high- and low-voltage issues were identified in each area for both the summer and winter peak cases, which meet the reporting requirements of Section 3.1. The worst voltage at a bus was listed for busses that violate their voltage criteria for multiple contingencies. For some of voltage constraints identified, the mitigation plan is operator actions. Appendix F presents the voltage results for all the areas.

# Section 4
# Enhancements

After determining potential "gaps" in the 2025 summer and winter roll-up cases, the planning authorities identified conceptual upgrades to inform the future planning cycles of their respective regional planning processes. This section lists the issues identified by each PA in Section 3, together with high-level conceptual upgrades and the entities with which the PAs will be coordinating on solutions in future planning cycles.

## 4.1 Issues List, Conceptual Upgrades, and Coordinating Entities

The PAs provided the following upgrades for the issues identified in their respective areas:

### ISO-NE

The *2015 New England Regional System Plan* provides an overview of the New England transmission system, updates on the performance of the system, and the status of several transmission planning studies.[14] The progress of current major transmission projects in the region and the various types of transmission upgrades taking place in the region are also provided.

### NYISO

Table 4-1 presents the NYISO area upgrades.

**Table 4-1**
**Upgrades in NYISO Area**

| PA | Facility Issue | Contingency | Conceptual Upgrades |
|---|---|---|---|
| NYISO | 130826 Meyer115 115.00 131345 S.Per115 115.00 1 | 130764 [Meyer230 230] - 130861 [S Perry 230] Ckt 1 | Reconfiguration |
| NYISO | 136052 Wetzel14 115.00 136181 Clay 115.00 1 | Sb:Oswe_R985 | Upgrade facility capacity |
| NYISO | 136052 Wetzel14 115.00 136192 Elect Pk 115.00 1 | Sb:Oswe_R985 | Upgrade facility capacity |
| NYISO | 137229 Kelsey H 115.00 137235 Porter 1 115.00 1 | B:Porter115d | Adding a reactor |

### IESO

For most of the thermal constraints identified in the IESO area, the mitigation plans are special protection systems. No additional upgrades were provided.

[14] The *2015 New England Regional System Plan* is available at http://www.iso-ne.com/system-planning/system-plans-studies/rsp.

## NB

NB did not provide any upgrades.

## MISO

Table 4-2 presents the upgrades in the MISO area.

**Table 4-2**
**Upgrades in MISO Area**

| PA | Facility Issue | Contingency | Conceptual Upgrades |
|---|---|---|---|
| MISO | 615560 Gre-Wst Cld7115.00 3wndtr 115/69 Wnd 2 1 | 619975 [Gre-Willmar 4230.00] - 652550 [Granitf4 230.00] Ckt 1 | Reconfiguration |
| MISO | 603018 Sheynne 7 115.00 620203 Mapltn 7 115.00 1 | 601067 [Bison 3 345.00] - 620358 [Buffalo 3 345.00] Ckt 1 | Line rebuild |
| MISO | 652452 Rugby 7 115.00 659665 Rugby Tap 7115.00 Z | 615335 [Gre-Ramsey 4230.0] - 615903 [Gre-Balta 4230.0] Ckt 1 | Reconfiguration |

## PJM

After the reviewing the initial thermal and voltage results, PJM provided a new contingency (PJM_updated.con) and monitor (PJM_2015.mon) file to rerun the analysis. The results presented in Table 3-15
and Table 3-16
are based on the new files provided by PJM.

PJM's assessment of the issues listed in the gap analysis attributes their cause primarily to increased load levels, generator interconnections requiring further study, local voltage-tuning issues, or issues that could be resolved with re-dispatch. Because all these issues will be addressed to the extent they materialize in the course of completing the necessary regional planning analysis, they are not expected to have an impact on interregional reliability and do not represent "gaps" in the interregional plans.

PJM supplied EIPC with PJM's RTEP model for the 2025S and 2025W future years to be incorporated into both roll-up cases. This model was concomitantly studied using PJM's criteria, and the upgrades resulting from this year's RTEP analysis for 2025S were incorporated into both roll-up models. The EIPC performed a screening analysis of the Eastern Interconnection case using screening techniques generally applicable to power system analysis. Each EIPC region also performs specific, detailed reliability analysis using region-specific techniques. PJM, therefore, performed an additional N-1 contingency analysis to both models after the incorporation of RTEP upgrades and using PJM specific techniques. No valid constraints to interregional transfers were detected. The results for facilities above 200 kV from the PJM analysis are depicted in Section 3 of this report. The thermal results presented are associated with the snapshot dispatch modeled in each case. The naturally occurring market dispatch of PJM's generation would alleviate these issues. The voltage results observed are associated with feeds to serve local load that could be voltage tuned for local analyses. These local issues do not have an adverse impact on the use of this case for interregional assessments.

### SPP

SPP did not provide any upgrades.

### SERC

In addition to the upgrades listed in Table 4-3, SERC has also provided a set of corrections to their system after reviewing the initial 2025 summer and winter peak cases.

**Table 4-3**
**Upgrades in the SERC Area**

| PA | Facility Issue | Contingency | Conceptual Upgrades |
|---|---|---|---|
| SERC | 317246 3elsnrsw3 115.00<br>317264 6elsnrsw6 230.00 1 | Base case | Reconfiguration |
| SERC | 381010 3bemiss 115.00<br>382549 3pine Grv B2115.00 1 | 381885 [6w Valdosta 230.00] - 381886 [3w Valdosta 115.00] Ckt 1 | Upgrade facility capacity |
| SERC | 311289 3forsbk 115.00<br>312820 3pine I 115.00 1 | 311716 [6bucksvl 230.00] - 311717 [3bucksvl 115.00] Ckt 1 | Second circuit added |
| SERC | 311716 6bucksvl 230.00<br>311717 3bucksvl 115.00 1 | Base case | Second circuit added |
| SERC | 312819 3perry R 115.00<br>312820 3pine I 115.00 1 | 311716 [6bucksvl 230.00] - 311717 [3bucksvl 115.00] Ckt 1 | Second circuit added |
| SERC | 311323 3campfld 115.00<br>312776 3greenf 115.00 1 | 311716 [6bucksvl 230.00] - 312719 [6winyah 230.00] Ckt 1 | New circuit added |
| SERC | 311609 3ngrnfdt 115.00<br>312776 3greenf 115.00 1 | 311716 [6bucksvl 230.00] - 312719 [6winyah 230.00] Ckt 1 | New circuit added |
| SERC | 311716 6bucksvl 230.00<br>312717 6perry R 230.00 1 | 311716 [6bucksvl 230.00] - 312717 [6perry R 230.00] Ckt 2 | Reconfiguration |

### FRCC

FRCC did not provide any upgrades.

## 4.2 Map of Future Transmission Projects (Projects Near PA Boundaries)

One of the tools used to facilitate inter-area coordination was a map of all proposed major transmission projects in the Eastern Interconnection (generally facilities greater than 230 kV), including major facilities near the boundaries of each PA. This map was built on a base map of existing transmission above 200 kV from the Ventyx Velocity Suite. Each Planning Authority provided input to modify the base layer to add projects to the map. This enables a view of proposed projects that might have interregional impacts. This map of proposed transmission is included in Appendix A.

Planning authorities may use this tool in future cycles to further monitor current transmission plans and potentially explore joint projects that may mutually benefit multiple regions and areas.

# Section 5
# Linear Transfer Analysis

There is increasing interest in knowing how much power can be reliably moved between regions. Because of the many interconnected paths and the need to remain reliable under contingencies, the capability of the power system to transfer power from one area to another is not a fixed value such as the capacity of a pipe, but rather a range of values based on the use of parallel paths. One tool available that can assist in assessing transfer capability between areas is linear transfer power-flow analysis. As used by the EIPC planning authorities, this analysis is not for identifying constraints and thus identifying projects and increasing transfer capability, but rather to illustrate the transmission grid's transfer capabilities as currently planned (based on the 2025 summer and winter roll-up cases) under a number of transfer patterns. The linear analysis performed involves thermal analysis only, which is used to evaluate the capability of the transmission facilities to withstand the thermal impact created by the increased electrical current flowing through the facilities. The thermal analysis did not examine system voltage, reactive supply, or stability issues, except to the extent that planning authorities apply thermal proxy limits to represent system stability limits.

## 5.1 Linear Transfer Analysis Inputs

The *Steady State Modeling Load-Flow Working Group Procedure Manual*, Section IV.B.3, identifies the specific linear power transfers performed and the associated details. Each PA supplied input files for the linear transfer power-flow analysis (e.g., monitored elements, subsystems, contingency files). Transfer subsystems were defined for exports and imports [(as described in the manual)] at a transfer test level of 5,000 MW for each transfer, with transfer amounts allocated among the importing areas on a load or generation-availability ratio share. Each transfer was assessed one at a time. However, because the transfers grouped multiple areas together as the source and as the sink, the analysis reflects simultaneous flows for the particular areas included in the transfer (see **Error! Reference source not found.** and **Error! Reference source not found.**).

**Table 5-1**
**Groupings of Planning Areas for Transfers**

| A | B | C | D | E | F |
|---|---|---|---|---|---|
| FPL | MAPPCOR | New York ISO | PJM | Duke Energy Carolinas | SPP |
| JEA | MISO | ISO New England | | Duke Energy Progress | |
| Duke Energy Florida | ATC | Ontario IESO | | LGE/KU | |
| | ITC | NBSO | | GTC | |
| | Entergy | | | Power South | |
| | | | | SCEG | |
| | | | | SC | |
| | | | | Southern Company | |
| | | | | MEAG | |
| | | | | Alcoa Power Generating, Inc. | |
| | | | | TVA | |
| | | | | Electric Energy, Inc. | |

**Table 5-2**
**Transfers Performed**

| Source | Sink | | | | | |
|---|---|---|---|---|---|---|
| | A | B | C | D | E | F |
| A | | | | | Y | |
| B | | | Y | Y | Y | Y |
| C | | Y | | Y | | |
| D | | Y | Y | | Y | |
| E | Y | Y | | Y | | Y |
| F | | Y | | | Y | |

**Error! Reference source not found.** and **Error! Reference source not found.** provide an overview of the transfers performed. **Error! Reference source not found.** shows the PAs grouped together for transfers as an area, while **Error! Reference source not found.** shows the combinations of areas (exporting [source] or importing [sink]) for which transfers were performed. For example, Group A includes FPL, JEA, and Duke Energy Florida in associated transfers performed. Note that participation in an area is only based on PAs that are party to the EIPC.

All facilities greater than 100 kV in the base-case model were monitored. Generally, single-contingency events for all facilities 161 kV and above in the base-case model, including generators as appropriate, were assessed. Known, approved, and applicable operating procedures were included in the contingency files.

## 5.2 Linear Transfer Analysis Process

The thermal-only linear analysis used PTI's PSS/MUST software to calculate transmission-transfer capabilities and did not examine system voltage, reactive supply, or stability issues.[15] Simulations were performed in batch mode, and the results of the study were assembled at the end.

Only those facilities with appreciable flows having a Transfer Distribution Factor (TDF) of 3.0% or greater were reported as limits. The TDF value indicates the percentage of the transfer being studied that actually is flowing on the identified transmission facility under the specific contingency condition. The 3.0% TDF cutoff for reporting is the value transmission planning analyses traditionally use to indicate that the transfer has a significant impact on the facility. A TDF less than 3.0% indicates that a facility, if reported, is already heavily loaded without the transfer in place.

If no constraint was identified up to the transfer test level of 5,000 MW, the limit reported was ">5,000," and further transfer capability was not evaluated.

## 5.3 Linear Transfer Analysis Results

Table 5-3 summarizes the results of the linear transfer analysis for 2025 summer peak conditions, and Table 5-4 summarizes the results of the linear transfer analysis for 2025 winter peak conditions. For each transfer, only the information for the lowest first-contingency incremental transfer capability (FCITC) is listed, along with branch information for the limiting element and associated contingency. The FCITC provides the amount of transfer capability incremental to the base-case interchange between the given subsystems.

[15] "PTI PSS™/MUST" refers to Siemens' Power Technologies International PSS™/Managing and Utilizing System Transmission.

Eastern Interconnection Planning Collaborative

**Table 5-3**
**Linear Transfer Analysis Results 2025 Summer Peak**

| Source | Sink | FCITC (MW) | Limiting Element | Lim. PA | Contingency / Outaged Facility | Con. PA |
|---|---|---|---|---|---|---|
| A | E | 343 | 403528 MARTIN WEST230 407120 SLV_SP_N 230 1 | DEF-SEC | 403173 BRNSNDUK 230 403522 CRYSTVRPL 230 | DEF |
| B | C | 2183 | 200674 26TOWANDA 115 200676 26E.SAYRE 115 1 | PJM | SB:HILL_B412 | NYISO |
| B | D | 4419 | 346809 7CASEY 345 347830 7NEWTON 345 1 | AMIL | Base case | N/A |
| B | E | >5000 | N/A | N/A | N/A | N/A |
| B | F | 404 | 337904 5RUSSELVL.S 161 505508 DARDANE5 161 1 | EES-EAI | 337909 8ANO% 500 515305 FTSMITH8 500 1 | EES-EAI |
| C | B | 1969 | 135460 PACK(N)E 115 147850 NIAG115E 115 2 | NYISO | T:61&191 | NYISO |
| C | D | 760 | 135460 PACK(N)E 115 147850 NIAG115E 115 2 | NYISO | T:61&191 | NYISO |
| D | B | >5000 | N/A | N/A | N/A | N/A |
| D | C | 1630 | 200674 26TOWANDA 115 200675 26ETWANDA 230 4 | PJM | R:C398/NWES | NYISO |
| D | E | >5000 | N/A | N/A | N/A | N/A |
| E | A | 2356 | 400398 HUDSONFL 230 407119 SEMINOLE230 1 | FPL | 400477 RICE 500 400484 ROBERTS 500 1 | FPL |
| E | B | >5000 | N/A | N/A | N/A | N/A |
| E | D | 4337 | 346809 7CASEY 345 347830 7NEWTON 345 1 | DVP | Base case | N/A |
| E | F | 336 | 337904 5RUSSELVL.S 161 505508 DARDANE5 161 1 | EES-EAI | 337909 8ANO% 500 515305 FTSMITH8 500 1 | EES-MISO / OKGE-SPP |
| F | B | 927 | 645456 S3456 3 345 645458 S3458 3 345 1 | OPPD | 645455 S3455 3 345 645740 S3740 3 345 1 | OPPD |
| F | E | 1397 | 645456 S3456 3 345 645458 S3458 3 345 1 | OPPD | 645455 S3455 3 345 645740 S3740 3 345 1 | OPPD |

**Table 5-4**
**Linear Transfer Analysis Results Summary 2025 Winter Peak Conditions**

| Source | Sink | FCITC (MW) | Limiting Element | Lim. PA | Contingency / Outaged Facility | Con. PA |
|---|---|---|---|---|---|---|
| A | E | 1130 | 400461 CAPE K 230 400494 TULSA 230 1 | FPL | 400476 POINSETT 500 400484 ROBERTS 500 1 | FPL |
| B | C | 2246 | 200674 26TOWANDA 115 200675 26E.TWAND 230 4 | PJM | R:C398/NWES | NYISO |
| B | D | >5000 | N/A | N/A | N/A | N/A |
| B | E | >5000 | N/A | N/A | N/A | N/A |
| B | F | 1275 | 337904 5RUSSELVL.S 161 505508 DARDANE5 161 1 | EES-EAI | 337909 8ANO% 500 515305 FTSMITH8 500 1 | EES-EAI |
| C | B | 2551 | 200004 CNASTONE 500 200013 PEACHBTM 500 1 | PJM | SB:OAKD345_32-B222 | NYISO |
| C | D | 1378 | 130762 GARDV230 130767 STOLE230 | NYISO | T:79&80 | NYISO |
| D | B | 1310 | 200004 CNASTONE 500 200013 PEACHBTM 500 1 | PJM | Base case | N/A |
| D | C | 2109 | 200674 26TOWANDA 115 200676 26E.SAYRE 115 1 | PJM | SB:HILL_B412 | NYISO |
| D | E | 1249 | 200004 CNASTONE 500 200013 PEACHBTM 500 1 | PJM | Base case | N/A |
| E | A | 2592 | 380015 8THALMANN 500 400356 DUVAL 500 1 | SOCO | 380014 8HATCH 500 400356 DUVAL 500 1 | SOCO |
| E | B | >5000 | N/A | N/A | N/A | N/A |
| E | D | >5000 | N/A | N/A | N/A | N/A |
| E | F | 1046 | 337905 5RUSSELVL.E! 161 337906 5RUSSELVLN 161 1 | EES-EAI | 337909 8ANO% 500 515305 FTSMITH8 500 1 | EES-MISO / OKGE-SPP |
| F | B | 4836 | 532765 HOYT 7 345 532766 JEC N 7 345 1 | OPPD | 532766 JEC N 7 345 532770 MORRIS 7 345 1 | OPPD |
| F | E | 5257 | 532765 HOYT 7 345 532766 JEC N 7 345 1 | OPPD | 532766 JEC N 7 345 532770 MORRIS 7 345 1 | OPPD |

The working group developed additional base cases with the base transfers shown in Table 5-5. These cases were for analyzing transfer directions highly dependent on phase angle regulator (PAR) settings in areas such as IESO and NYISO for import and export transfers from and to the NPCC region. The incremental transfer megawatts presented in the tables for all the NPCC transfers include these base transfers. Appendix D contains more detailed results for each subsystem's linear transfer analysis, including the next five valid limits beyond the most limiting facility. The PJM facility and the tie facility limiting transfers to negative values in the winter scenario result from the setup of the reference transfer case that did not include adjustments for normal operating practice. These transfers are typically achievable in daily operations.

**Table 5-5**
**Base Transfers Modeled in the NPCC Transfer Analysis (MW)**

| From\To | NPCC | MISO | PJM |
|---|---|---|---|
| **NPCC** | | 1,800 | 1,600 |
| **MISO** | 1,800 | | |
| **PJM** | 3,000 | | |

# Appendix A: Future Project Map

This appendix now exists as an attached .pdf map ("EIPC Roll-up Appendix A Transmission Map").

# Appendix B: New/Upgraded Transmission Projects

This appendix now exists as part of a Microsoft Excel workbook.

# Appendix C: New/Upgraded Generation Included in Roll-Up Model

This appendix now exists as part of a Microsoft Excel workbook.

# Appendix D: Linear Transfer Analysis Results

This appendix now exists as two Microsoft Excel workbooks:

1. EIPC_AppendixD_2025_Summer
2. EIPC_AppendixD_2025_Winter

This appendix contains more detailed results for each subsystem's linear transfer analysis, including the next five valid limits beyond the most limiting facility. The most limiting facility is highlighted in yellow.

# Appendix E: Area Interchange Tables

This appendix now exists as two Microsoft Excel workbooks:

1. EIPC_AppendixE_2025_Summer
2. EIPC_AppendixE_2025_Winter

# Appendix F: N-1 Voltage Results

This appendix now exists as two Microsoft Excel workbooks:

1. EIPC_Voltage_Results_AppendixC_2025_Summer
2. EIPC_Voltage_Results_ AppendixC_2025_Winter

This appendix contains the detailed voltage results for each PA.

The following points should be considered when assessing the PJM voltage results:

- Most voltage issues are inherently local in nature, amenable to local remedies, and therefore not a focus of interregional case preparation.
- Many results are for lower-voltage facilities even more so of a local interest and likely amenable to local system adjustments.
- Many contingency results show little change from the reference case and are likely amenable to voltage tuning of the reference case voltage.
- The large increase in winter results compared with summer, and the fact that winter results are dominated by high voltages, is evidence that local adjustments to the winter reference case is a likely solution for many of these issues.
- Many high voltages can occur on transmission lines greater than 400 kV often designed and operated at these higher voltages.

These result from general screening and may not be issues at all. Overall, the PJM voltage results do not indicate significant interregional issues.